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April 7, 2008

Stephanie Stumbo
PO Box 615
211 Sower Blvd.
Frankfort, KY 40601

Dear Ms. Stumbo:

Enclosed are 3 CD's with the articles and exhibits to go along with the Response. Sorry for the delay.

Sincerely,

Ashley Addington

Ashley Addington
Secretary for Stephen Sanders

The Carbon Principles

The Intent

We the undersigned financial institutions have come together to advance a set of principles for meeting energy needs in the United States (US) that balance cost, reliability and greenhouse gas (GHG) concerns.[1] The principles focus on a portfolio approach that includes efficiency, renewable and low carbon power sources, as well as centralized generation sources in light of concerns regarding the impact of GHG emissions while recognizing the need to provide reliable power at a reasonable cost to consumers. The Carbon Principles ("the Principles") represent the first time that financial institutions, advised by their clients and environmental advocacy groups, have jointly committed to advance a consistent approach to the issue of climate change in the US electric power industry.

We advance these Principles to create an industry best practice for the evaluation of options to meet the electric power needs of the US in an environmentally responsible and cost effective manner. When evaluating the financing of new fossil fuel generation we will be guided by the Principles and employ the accompanying Enhanced Environmental Diligence Process (the "Enhanced Diligence Process") to assess project economics and financing parameters related to the uncertainties around current climate change policy in the US. The Enhanced Diligence Process will evaluate the ability of the proposed financing to meet financial requirements under a range of potential GHG emissions assumptions and parameters. These assumptions will include policies regarding CO_2 emission controls and potential future CO_2 emissions costs as well as the costs and feasibility of mitigating technologies or other mechanisms. Due to the uncertainties around many of these factors, the Enhanced Diligence Process will encourage consideration of assumptions that err on the side of caution until more clarity on these issues is available to developers, lenders and investors. Financial institutions that adopt the Principles will implement them with the accompanying Enhanced Diligence Process, while consulting with environmental groups and energy companies.

The Carbon Principles

Energy efficiency. An effective way to limit CO_2 emissions is to not produce them. We will encourage clients to invest in cost-effective demand reduction, taking into consideration the potential value of avoided CO_2 emissions. We will also encourage regulatory and legislative changes that increase efficiency in electricity consumption including the removal of barriers to investment in cost-effective demand reduction. We will consider demand reduction caused by increased energy efficiency (or other means) as part of the Enhanced Diligence Process and assess its impact on proposed financings of new fossil fuel generation.

Renewable and low carbon energy technologies. Renewable energy and low carbon distributed energy technologies hold considerable promise for meeting the electricity needs of the US while also leveraging American technology and creating jobs. We will encourage clients to invest in cost-effective renewables, fuel cells and other low carbon technologies, taking into consideration the potential value of avoided CO_2 emissions.

[1] We consider all greenhouse gases but refer to CO2 which is the most significant.

We will also support legislative and regulatory changes that remove barriers to, and promote such investments (including related investments in infrastructure and equipment needed to support the connection of renewable sources to the system). We will consider production increases from renewable and low carbon generation as part of the Enhanced Diligence Process and assess their impact on proposed financings of new fossil fuel generation.

Conventional or Advanced generation. In addition to cost effective energy efficiency, renewables and low carbon generation, we believe investments in other generating technologies likely will be needed to supply reliable electric power to the US market. This may include power from natural gas, coal and nuclear[2] technologies. Due to evolving climate policy, investing in CO_2-emitting fossil fuel generation entails uncertain financial, regulatory and environmental liability risks. It is the purpose of the Enhanced Diligence Process to assess and reflect these risks in the financing considerations for fossil fuel generation. We will encourage regulatory and legislative changes that facilitate carbon mitigation technologies such as carbon capture and storage (CCS) to further reduce CO_2 emissions from the electric sector.

New fossil fuel generation constructed with conventional technology, if not accompanied by mitigation measures, will increase the emission of CO_2 into the atmosphere at a time when federal and state level emissions controls seem likely and, in some regions of the country, are already mandated. An important aspect of the Enhanced Diligence Process will be to evaluate the mitigation strategy and plan of the developer to address the risks posed by the increased CO_2 emissions from new sources when future emissions controls are uncertain. For projects proposed in jurisdictions that already have controls on emissions in place, the developer will need to show how the new generation will be consistent with the existing rules and potential changes going forward. However, in the absence of regional or federal regulations, the development plan will need to account for the added risks due to the uncertainties around future emissions limits.

The Commitments

Adopters commit to:

- Encourage clients to pursue cost-effective energy efficiency, renewable energy and other low carbon alternatives to conventional generation, taking into consideration the potential value of avoided CO_2 emissions.

- Ascertain and evaluate the financial and operational risk to fossil fuel generation financings posed by the prospect of domestic CO_2 emissions controls through the application of the Enhanced Diligence Process. Use the results of this diligence as a contribution to the determination whether a transaction is eligible for financing and under what terms.

- Educate clients, regulators, and other industry participants regarding the additional diligence required for fossil fuel generation financings, and encourage regulatory and legislative changes consistent with the Principles.

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[2] It is recognized that nuclear plants carry a host of risks that financial institutions must consider, but which are outside the scope of these principles.

We Adopt the above Principles and Commitments

Citi

JP Morgan Chase

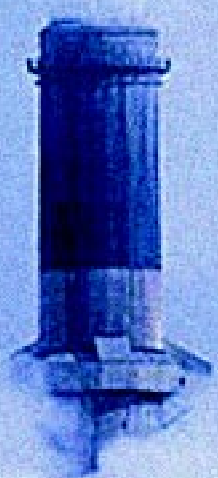
Morgan Stanley

CLEAR THE AIR

OCTOBER 2000

Death, Disease & Dirty Power

Mortality and Health Damage Due to Air Pollution from Power Plants



Clean Air Task Force

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This report and the full Abt Associates report,
The Particulate-Related Health Benefits of Reducing Power Plant Emissions
(October 2000),
are available at the Clear the Air website:

www.cleartheair.org

Credits:

This report was made possible with funding from the Pew Charitable Trusts. The opinions expressed in this report are those of the authors and do not necessarily reflect the views of the Pew Charitable Trusts.

Written by: **Conrad G. Schneider**, Clean Air Task Force

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October 2000

Foreword

John D. Spengler, *Professor of Environmental Health, Harvard School of Public Health (Boston, September 2000)*

On December 5, 1952, the residents of London, England awoke to the dawn of a five-day reign of death. A temperature inversion had trapped the coal smoke from the city's furnaces, fireplaces, and industrial smokestacks, creating a "killer fog" that hovered near the ground. People began to die from respiratory and cardiopulmonary failure. Not until the weather system that had trapped London's pollution finally loosened its grip and the soot-filled air cleared out did death rates return to normal. The end of the episode saw more than three thousand dead; a five-fold increase over the normal death rate.

While incidents like London's "killer fog" of 1952 clearly demonstrate a link between air pollution and death, only in the past decade have tremendous advances in medical science and epidemiology allowed researchers to quantify the health impacts of everyday air pollution levels. In studies conducted in cities throughout the world, epidemiologists have consistently found that more people are hospitalized and die from respiratory and cardiac failure in proportion to elevated levels of soot, or "fine particles," and other pollutants. The consistent worldwide findings, combined with a much clearer understanding about how we are exposed to outdoor air pollution, have convinced most experts that these results are not a coincidence. In particular, two landmark studies established that people living in more polluted areas suffer a higher risk of death from fine particle pollution than those living in less polluted areas.

These studies and many others formed the basis of U.S. EPA's 1997 decision to issue a new national ambient air quality standard for "fine particles" known as $PM_{2.5}$ and defined as particles smaller than 2.5 microns—one millionth of a meter in diameter (less than one-hundredth of the width of a human hair). EPA estimated that attaining the annual fine particle levels required by the new standard would prevent 15,000 deaths per year. And recent monitoring data suggests that if present air pollution levels persist, the health standard EPA established will be violated every year in hundreds of communities in the U.S. What is more, as EPA acknowledged, the science underlying the standard indicates that deaths occur even at levels below the standard. Indeed, the science now tells us that health effects extend to lower levels of fine particles in our air, suggesting there is no definite threshold below which the air is safe to breathe.

Not surprisingly, industries that contribute to this air pollution, such as the electric utility industry and diesel trucking industry, are disputing EPA's decision and the science on which it was based. They claim EPA relied on "junk science" and then sued in court to block the standards. They demanded access to the data underlying the seminal studies to help refute the results. In the end, the Health Effects Institute, a research center co-funded by industry and EPA and founded to be a neutral arbiter for policy-related health science disputes, was called upon to reanalyze the studies.

This past summer, HEI announced the results of its reanalysis, which unequivocally confirmed the findings of the two major studies underlying the fine particle standard. HEI also released a new study that further supports the link between particles and death. And while the fate of the fine particle standard itself awaits resolution in the courts, there is no longer any legitimate doubt that fine particles at levels commonly experienced in many parts of the U.S. contribute significantly to death and disease.

Most of the coal used in this country today is burned by aging power plants for the production of electricity. In a variety of contexts, researchers have sought to quantify the contribution to fine particle health impacts made by these plants. Health researchers have employed some assessment methods to estimate the relative contribution of power plants to total deaths. EPA's Regulatory Impact Analysis for the $PM_{2.5}$ National Ambient Air Quality Standard ("NAAQS") examined the contribution of power plant emissions to fine particle concentrations in our air. In addition, EPA's cost-benefit analyses of the Clean Air Act included the benefits associated with expected reductions in power plant-generated fine particle pollution, providing strong justification for the emission control costs imposed by the Act. More recently, in a study of two coal-fired power plants in Massachusetts, my Harvard School of Public Health colleague Jonathan Levy and I found that fine particle pollution from these two plants alone is associated with over 100 deaths annually.

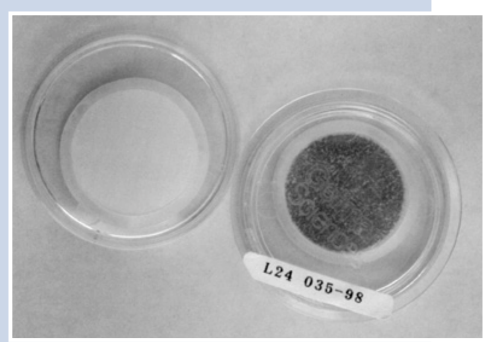
Now, employing the same analytic tools used by the U.S. EPA in a variety of policy-setting and regulatory decisionmaking contexts, Abt Associates has provided the most rigorous look to date at the contribution of air emissions from the nation's power plants to fine particle levels and the impact of those emissions on human health. Abt Associates' work builds on methods used by the U.S. EPA in developing important air quality standards and assessing its air regulatory programs. Abt Associates finds that power plant pollution contributes to several thousand deaths each year. In short, these findings imply that our regulatory strategies and priorities should be reconsidered. A variety of policies could help lower the risks posed by power plant pollution — from broader application of existing pollution control technologies, to use of cleaner fossil fuels, to ultimate replacement of the existing energy infrastructure with more sustainable means of producing electricity. We can only hope the information provided through this study will help crystallize the policy debate around the need for actions to reduce the health risks posed by the pollution produced by our current energy system.

The Abt Associates approach enables us to combine information from many well-done studies to derive a quantitative relationship between air pollution and health effects. These studies tell us that the concept of a threshold demarcating safe from unhealthy air is now outdated. They provide continuous damage functions that lead us to expect benefits from deeper and deeper reductions in air pollution. The insight derived from this new analytical approach provides important information to the benefit side of the cost-benefit debate. The debate over the policy consequences of this shift in thinking may be difficult and acrimonious in the near term as power companies, regulators, lawmakers, and citizens adjust to new concepts of incorporating health damage costs into control strategies, weigh local impacts versus regional damage, and consider the appropriateness of emission reduction trading among pollution sources. The primary advantage of a quantitative method to assess air pollution effects with no threshold is that it represents more accurately the biological reality. The old threshold concept appears even more outmoded when we consider the notion of "safe" levels for each of the hundreds of contaminants in the air. We will all benefit from this emerging methodology that brings air pollution health research into the public decisionmaking process. All of us, throughout our lives, are susceptible to the adverse effects of air pollution. Now, our health interests can be more directly incorporated into the debate over our energy, environmental, and economic future.

All of us, throughout our lives, are susceptible to the effects of air pollution.

What are Fine Particles?

Fine particles are a mixture of a variety of different compounds and pollutants that originate primarily from combustion sources such as power plants, diesel trucks and buses, cars, etc. They are sometimes referred to as $PM_{2.5}$ (particulate matter smaller than 2.5 microns in diameter — less than one-hundredth of the width of a human hair). Fine particles are either emitted directly from these combustion sources or are formed in the atmosphere through complex oxidation reactions involving gases, such as sulfur dioxide (SO_2) or nitrogen oxides (NO_X). Among particles, fine particles are of gravest concern because they are so tiny that they can be inhaled deeply, thus evading the human lungs' natural defenses.



Fine particle filters: clean and exposed 24 hours.

Executive Summary

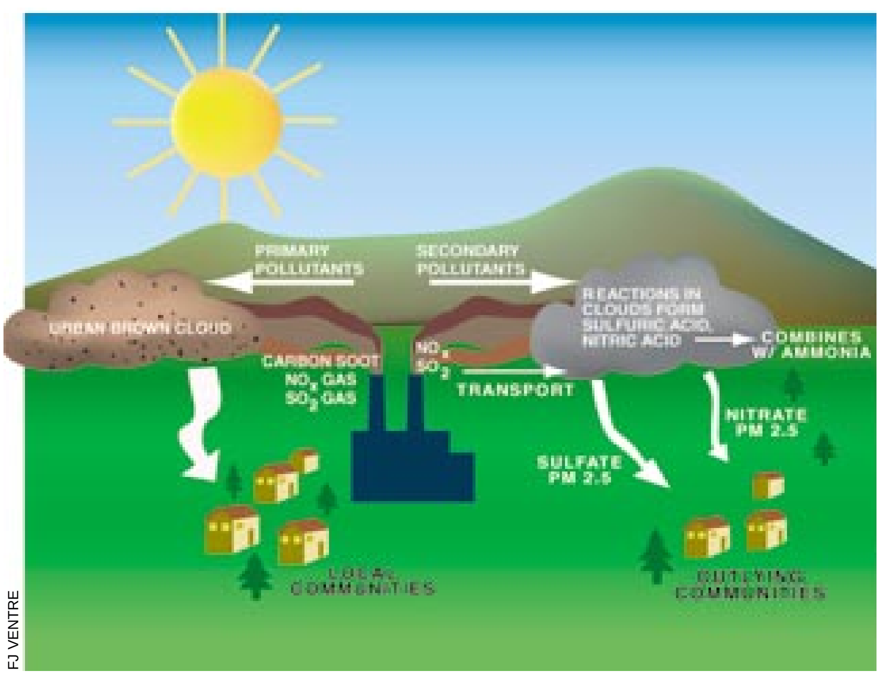
The Clean Air Task Force, on behalf of the Clear the Air campaign, commissioned Abt Associates to quantify the health impacts of fine particle air pollution, commonly known as soot, from power plants, as well as the expected benefits (avoidable deaths, hospitalizations, etc.) of policies that would reduce fine particle pollution from power plants. The health effects analyzed include death, hospitalizations, emergency room visits, asthma attacks, and a variety of lesser respiratory symptoms.

This report summarizes the findings of the Abt Associates study, reviews the contribution of power plants to fine particle pollution, and discusses policies that will reduce power plant fine particle pollution and thus save thousands of lives. Key findings include:

- Fine particle pollution from U.S. power plants cuts short the lives of over 30,000 people each year.
- In more polluted areas, fine particle pollution can shave several years off its victims' lives.
- Hundreds of thousands of Americans suffer from asthma attacks, cardiac problems and upper and lower respiratory problems associated with fine particles from power plants.
- The elderly, children, and those with respiratory disease are most severely impacted by fine particle pollution from power plants.
- Metropolitan areas with large populations near coal-fired power plants feel their impacts most acutely – their attributable death rates are much higher than in areas with few or no coal-fired power plants.
- Power plants outstrip all other polluters as the largest source of sulfates – the major component of fine particle pollution – in the U.S.
- Approximately two-thirds (over 18,000) of the deaths due to fine particle pollution from power plants could be avoided by implementing policies that cut power plant sulfur dioxide and nitrogen oxide pollution 75 percent below 1997 emission levels.

Fine particle pollution is responsible for increased risk of death and shortened life spans. Abt Associates' findings are based on a body of well-accepted scientific work on the health effects of fine particle pollution. The discussion at pages 12-16 of the report contains an extensive review of the scientific studies used by Abt Associates linking fine particle pollution to death and

Power Plant Particle Formation



FJ VENTRE

Fine particles are emitted directly or formed in the atmosphere through complex reactions.

other health damages. The methodology of how the Abt Associates analysis was performed is discussed at pages 16-17 of this report.

Recommendations

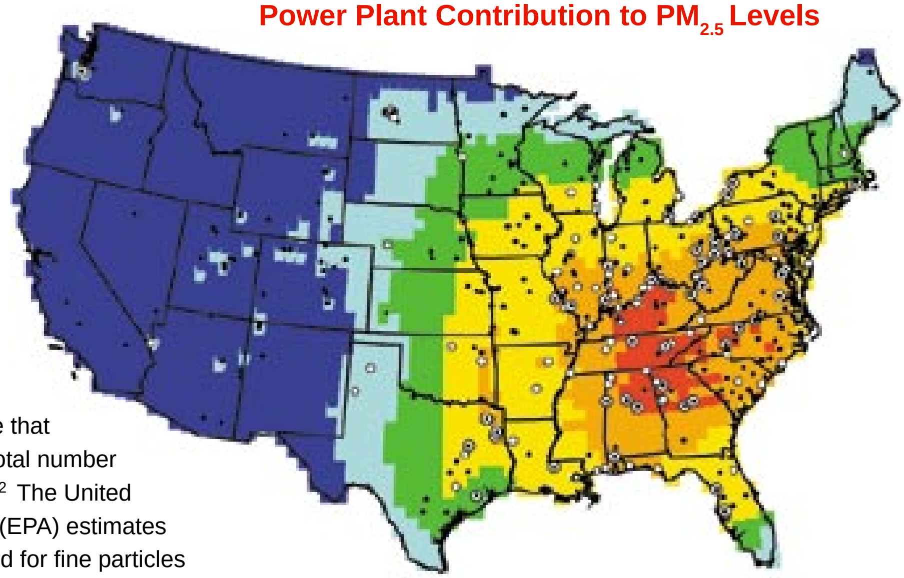
For over thirty years the oldest, dirtiest coal-burning power plants have circumvented the most protective air emissions standards required of modern plants. As a result, these so-called “grandfathered” power plants are permitted to emit as much as 10 times more nitrogen oxides and sulfur dioxide than modern coal plants. Polluting coal-fired power plants must be made to comply with modern emissions control standards. In addition, the nation’s power fleet should be held to stringent caps on all four of the key power plant pollutants including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. The deaths, hospitalizations and lost work time caused by fine particles from power plants can be reduced comprehensively only when the Clean Air Act’s 30-year loophole for old, dirty power plants is finally closed. Requirements such as these can ensure that U.S. energy policy better accounts for the public health and environmental costs associated with electricity production and will propel us toward a more sustainable energy future that relies increasingly on renewable energy resources and conservation.

New Findings

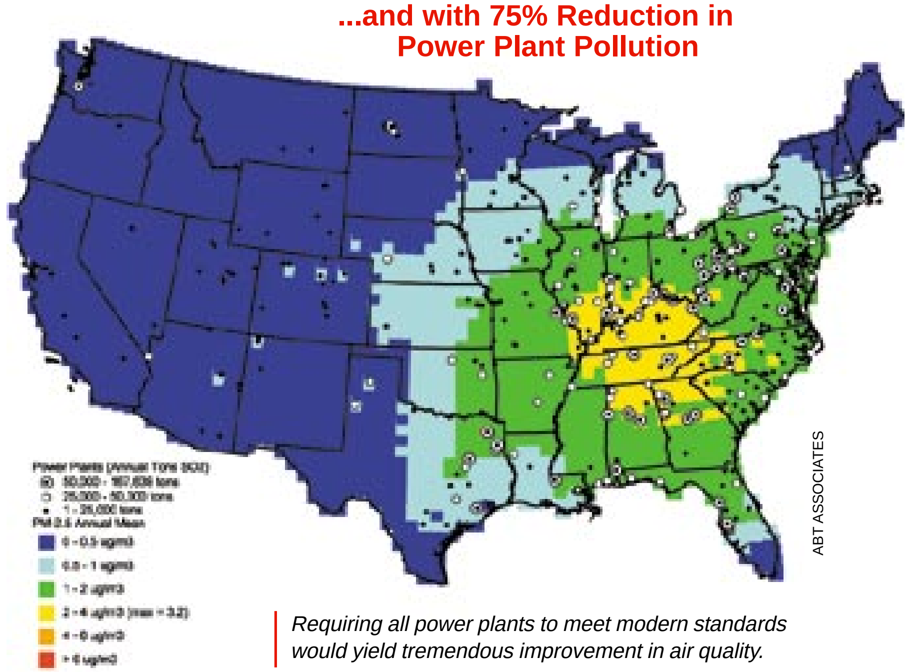
Numerous studies over the years have linked fine particles to a variety of health damages, from increased asthma attacks to hospital visits to death. Researchers estimate that as many as 60,000 people die prematurely each year because of exposure to fine particles.[1] And some researchers believe that this figure may even underestimate the total number of deaths due to fine particles in the U.S.[2] The United States Environmental Protection Agency (EPA) estimates that attainment of the new health standard for fine particles alone could save 15,000 lives each year.[3] However, to date there has been no definitive study quantifying the deaths and other health effects attributable solely to fine particles from power plant pollution.

Now, for the first time, this report reveals the power industry’s staggering share of the toll of death and disease from fine particles in our air. Using peer-reviewed, state-of-the-art research methodology, Abt Associates finds over 30,000 deaths each year are attributable to fine particle pollution from U.S. power plants. The underlying research shows that these people are dying months or years earlier because of power plant air pollution. Further, the study finds that by requiring the nation’s

Power Plant Contribution to $PM_{2.5}$ Levels



...and with 75% Reduction in Power Plant Pollution



ABT ASSOCIATES

Requiring all power plants to meet modern standards would yield tremendous improvement in air quality.

fleet of older, dirty power plants to cut their sulfur dioxide and nitrogen oxide emissions by 75 percent, consistent with current legislative proposals,[4] approximately two-thirds (over 18,000) of these deaths could be avoided.[5]

The deaths from power plant pollution exceed the death toll from other causes commonly understood to be major public policy priorities. For instance, drunk driving causes nearly 16,000 deaths per year.[6] There are over 17,000 homicides in the U.S. each year.[7] Moreover, the 18,000 deaths that could be avoided by cleaning up the nation's power plants are three times the number of automobile fatalities avoided each year through the use of safety belts.[8] Among air pollution sources, the deaths attributable to power plants are rivaled only by those due to the fine particle pollution from the combined total of all the diesel trucks, buses, locomotives, and construction equipment in the U.S. which, according to the Abt Associates analysis, are responsible for approximately 80 percent of the deaths attributable to power plants.

The Abt Associates report further shows that hundreds of thousands of Americans suffer from asthma attacks, cardiac problems and upper and lower respiratory ailments associated with fine particles from power plants. These health damages result in thousands of respiratory and cardiopulmonary-related hospitalizations and emergency room visits as well as hundreds of thousands of lost work and school days, many of which could be avoided by cleaning up older power plants. For instance, the study finds that power plant particle pollution causes more than 603,000 asthma attacks per year, 366,000 of which could be avoided by cleaning up power plants to modern standards.

Respiratory distress severe enough to require a trip to the emergency room can be a terrifying experience for patients and their families. Victims of asthma attacks say that during an attack they wonder if and when their next breath will come. In addition to these serious physical and emotional costs, air pollution also wracks up large monetary costs. Emergency room and hospital treatment costs can cripple a family financially. The average hospital stay for a respiratory ailment lasts about a week.[9] Bouts of respiratory illness and asthma attacks mean lost workdays for workers and lost productivity for their employers. And, although priceless, in a variety of contexts we place a monetary value on the loss of human life. Using accepted valuation methodology employed by EPA in its regulatory impact analyses, Abt Associates finds that the total monetary benefits of cleaning up power plants to modern pollution standards would be over $100 billion per year.

National Power Plant Health Impacts

Health Effect	Study	Incidence (cases/year): Avoided by 75% Power Plant Reduction	Incidence (cases/year): Power Plant Total
Mortality	HEI, 2000 Pope Reanalysis (Annual mean, All Cause)	18,700	30,100
All Respiratory and Cardio-vascular Hospitalizations	Pooled COPD+Respiratory+ Asthma+CardioVascular	12,200	20,100
Asthma-Related Emergency Room Visits	Schwartz et al., 1993	4,320	7,160
Chronic Bronchitis	Pooled	11,400	18,600
Asthma Attacks	Whittemore and Korn, 1980	366,000	603,000
Lost Work Days	Ostro, 1987 - WLDs	3,190,000	5,130,000
Minor Restricted Activity Days	Ostro and Rothschild, 1989	16,400,000	26,300,000

By modeling the impact of power plant pollution throughout the lower 48 states, Abt Associates developed health impact estimates for every state and major metropolitan area. Not surprisingly, states with large populations in close proximity to many coal-fired power plants fared the worst.

States: Health Impacts

	State	Mortality	Total Hospital-izations	Asthma Attacks
1	Pennsylvania	2,250	1,510	38,400
2	Ohio	1,920	1,250	37,100
3	New York	1,870	1,260	37,000
4	North Carolina	1,800	1,200	37,100
5	Florida	1,740	1,350	30,800
6	Illinois	1,700	1,110	33,100
7	Georgia	1,630	1,050	38,200
8	Tennessee	1,440	910	27,100
9	Texas	1,310	885	31,700
10	Virginia	1,240	823	27,900
11	Alabama	1,110	701	20,600
12	New Jersey	1,100	758	21,900
13	Indiana	1,030	679	20,500
14	Kentucky	997	635	19,000
15	Maryland	927	608	20,900

...and Avoided by a 75% Reduction

	State	Mortality	Total Hospital-izations	Asthma Attacks
1	Pennsylvania	1,460	947	24,200
2	New York	1,200	792	23,200
3	Ohio	1,200	768	22,800
4	North Carolina	1,190	771	24,000
5	Georgia	1,090	688	25,200
6	Florida	1,050	760	17,300
7	Illinois	981	635	19,000
8	Tennessee	857	533	15,900
9	Virginia	828	542	18,400
10	Texas	805	534	19,100
11	Alabama	738	459	13,500
12	New Jersey	718	481	13,900
13	Maryland	619	397	13,700
14	Indiana	585	379	11,500
15	Kentucky	578	360	10,900

Conversely, states with large populations but without coal-fired plants fared much better. For example, California, which has the nation's largest population and some of its worst air quality, has very few coal or oil-fired power plants. Abt Associates estimates that only 259 deaths are attributable to power plant pollution in California and the state ranked almost *last* in per capita impact (1.4 deaths per 100,000 adults). Kentucky, the state with the highest reliance on coal for production of electricity ranked first in related per capita mortality at more than 44 deaths per 100,000 adults, *over 30 times higher* than California's per capita mortality rate.

Note — For complete tables, see Appendix.

States: Per Capita Deaths

	State	Total Power Plant Deaths	Avoided by 75% Reduction	Deaths per 100,000 adults
1	Kentucky	997	578	44.1
2	West Virginia	459	296	43.3
3	Alabama	1,110	738	42.8
4	Tennessee	1,440	857	42.3
5	District of Columbia	118	80	41.3
6	North Carolina	1,800	1,190	38.6
7	South Carolina	791	515	36.0
8	Georgia	1,630	1,090	35.5
9	Mississippi	489	318	32.2
10	Pennsylvania	2,250	1,460	32.0
11	Arkansas	479	277	30.7
12	Virginia	1,240	828	30.3
13	Indiana	1,030	585	30.0
14	Ohio	1,920	1,200	29.7
15	Maryland	927	619	28.8
	....	....	....	....
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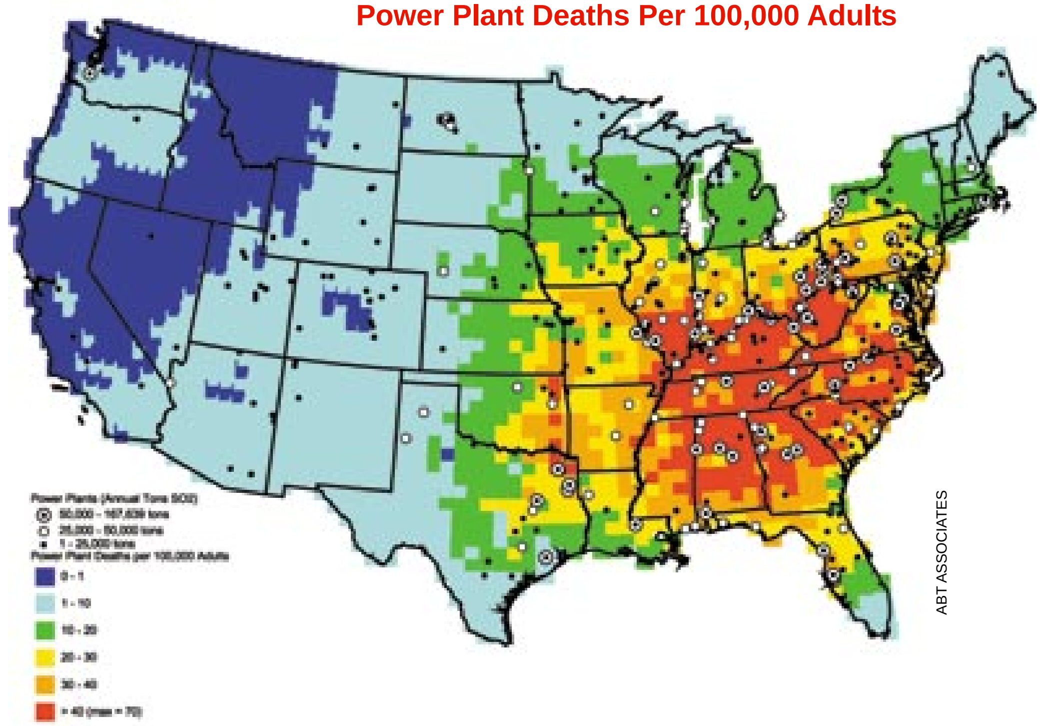
46	California	259	49	1.4

Similarly, metropolitan areas with large populations near coal-fired power plants feel their impacts most acutely. In large metropolitan areas, many hundreds of lives are shortened each year.

States in "coal country" suffer the greatest per capita impacts.

Power Plant Deaths Per 100,000 Adults



Metro Areas: Health Impacts

	Metropolitan Statistical Area	Mortality	Total Hospital-izations	Asthma Attacks
1	New York, NY	2,290	1,580	46,200
2	Washington, DC	1,140	764	28,600
3	Philadelphia, PA	997	654	19,000
4	Chicago, IL	995	648	21,400
5	Atlanta, GA	647	432	18,700
6	Pittsburgh, PA	585	395	9,210
7	Detroit, MI	527	343	11,200
8	St. Louis, MO	494	309	9,200
9	Tampa, FL	494	409	8,070
10	Boston, MA	454	320	9,540
11	Akron, OH	442	293	8,170
12	Cincinnati, OH	377	248	7,870
13	Dallas, TX	369	247	10,500
14	Greensboro, NC	309	210	6,380
15	Charlotte, NC	298	201	6,780
16	Nashville, TN	260	167	5,800
17	Birmingham, AL	257	164	4,760
18	Louisville, KY	256	162	4,870
19	Indianapolis, IN	250	161	5,300
20	Greenville, SC	226	148	4,520

...and Avoided by a 75% Reduction

	Metropolitan Statistical Area	Mortality	Total Hospital-izations	Asthma Attacks
1	New York, NY	1,470	991	29,000
2	Washington, DC	762	501	18,800
3	Philadelphia, PA	647	406	11,700
4	Chicago, IL	572	368	12,200
5	Atlanta, GA	431	283	12,300
6	Pittsburgh, PA	371	241	5,620
7	Detroit, MI	322	207	6,740
8	Tampa, FL	291	211	4,040
9	Boston, MA	287	198	5,880
10	Akron, OH	283	185	5,160
11	St. Louis, MO	280	170	5,060
12	Dallas, TX	228	151	6,390
13	Cincinnati, OH	223	144	4,590
14	Greensboro, NC	207	137	4,180
15	Charlotte, NC	191	125	4,240
16	Birmingham, AL	174	109	3,170
17	Norfolk, VA	150	97	3,750
18	Nashville, TN	149	95	3,300
19	Greenville, SC	145	93	2,860
20	Indianapolis, IN	145	91	3,000

However, much smaller metropolitan areas in and around “coal country” suffer the greatest per capita impacts, such as Chattanooga, Tennessee; Gadsden, Alabama; Terre Haute, Indiana; Wheeling, West Virginia; and Owensboro, Kentucky. Their death rates are much higher, for example, than that of New York City. Compare Chattanooga at 49.3 deaths per 100,000 adults with New York at 19.3 per 100,000.

In fact, because these health effects estimates include only the effects from airborne fine particles, they significantly understate the total adverse impact on public health from power plants. Excluded from these estimates are the health effects from other power plant pollutants, such as air emissions that result in ozone smog, air toxics, global warming, and the impacts from the consumption of fish contaminated by power plant mercury emissions.

Note — Complete state and metropolitan area tables are included in the Abt Associates report.

The full Abt Associates report is available at the Clear the Air website

www.cleartheair.org

Power plants are significant contributors to fine particle levels in vast areas of the United States.

Metro Areas: Per Capita Deaths

	Metropolitan Statistical Area	Total Power Plant Deaths	Avoided by 75% Reduction	Deaths per 100,000 adults
1	Gadsden, AL	41	27	59.0
2	Chattanooga, TN	154	100	49.3
3	Anniston, AL	37	25	49.0
4	Florence, AL	43	27	48.2
5	Johnson City, TN	154	93	48.0
6	Asheville, NC	69	44	46.9
7	Terre Haute, IN	44	25	46.8
8	Cumberland, MD	33	22	46.5
9	Birmingham, AL	257	174	46.0
10	Danville, VA	35	24	45.6
11	Owensboro, KY	24	12	45.0
12	Knoxville, TN	190	114	44.5
13	Wheeling, WV	46	30	44.5
14	Huntington, WV	86	55	44.0
15	Charleston, WV	69	44	43.3
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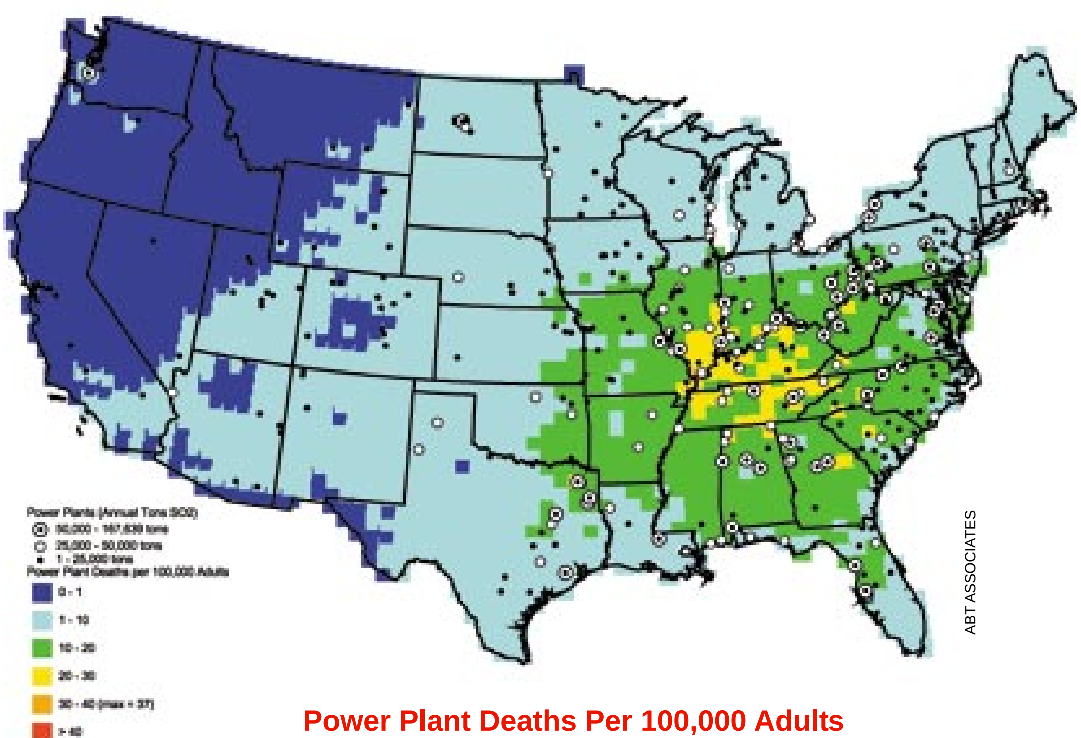
138	New York, NY	2,290	1,470	19.3



Power Plant Deaths Per 100,000 Adults with 75% Reduction in Power Plant Pollution

Children, the Elderly, and People with Respiratory Disease Face the Greatest Risk

While all of us are at risk from exposure to fine particles, the elderly, people with respiratory disease, and children are at greatest risk. Young children need to be healthy to play, to learn, and to grow into strong adults. School age kids find participating in sports and even studying difficult when battling respiratory problems. Studies estimate that tens of thousands of elderly people die each year from exposure to ambient levels of fine particles. Fine particles are also associated with tens of thousands of hospital admissions annually. Many of

these hospital admissions involve elderly people already suffering from lung or heart disease. Respiratory ailments can rob the elderly of the full enjoyment of their sunset years. Breathing fine particles can also hurt individuals of any age with heart disease, emphysema, and chronic bronchitis by forcing them to require additional medical treatment. People struggling with these ailments try to cope by limiting their exposure to respiratory irritants in their environment, but they cannot control the quality of the outdoor air they breathe.

Children at Risk

Children are at special risk: they breathe 50 percent more air per pound of body weight than adults do. Because children's respiratory systems are still developing, they generally are more susceptible to environmental threats than healthy adults. Damage caused by air pollution can mean they never reach their potential lung development. Exposure to fine particles is associated with increased frequency of childhood illnesses, which are of concern both in the short run, and for the future development of healthy lungs in the affected children. Babies and young children are especially susceptible to fine particles.

A recent study found a 26 percent increased risk for Sudden Infant Death Syndrome (SIDS) in cities with high levels of fine particle pollution.[10] Moreover, infants in high pollution areas were 40 percent more likely to die of respiratory causes.[11] Fine particles are also associated with increased respiratory symptoms and reduced lung function in children, including symptoms such as aggravated coughing and difficulty or pain in breathing. These can result in school absences and limitations in normal childhood activities.

Breathing fine particles aggravates asthma symptoms and while children make up 25 percent of the population, they comprise 40 percent of all asthma cases.[12] Asthmatic children who breathe fine particles use more medication, receive more medical treatment, and visit the hospital more often.

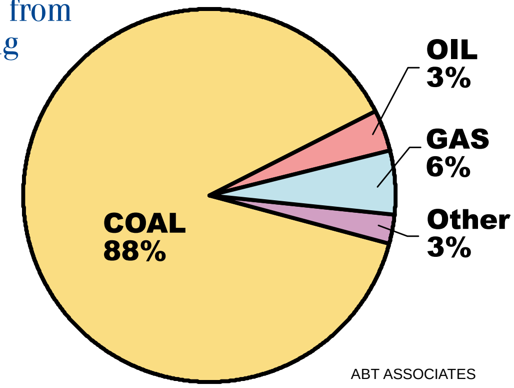
Coal-burning Power Plants: #1 Source

The link between power plants and fine particles is clear. In most areas of the country, sulfate — acidic fine particles — dominate the total mass of fine particle pollution measured at monitors located throughout the United States. And power plants outstrip all other polluters as the largest source of sulfate air pollution in the U.S.[13] In 1998, power plants were responsible for 67 percent—a full two thirds—of the annual total sulfur dioxide (SO_2) and over a quarter of the nitrogen oxides (NO_X) emitted in the U.S.;[14] over 13 million tons of SO_2 and over six million tons of NO_X.[15] Sulfur dioxide and NO_X gas emissions from power plants form fine particles as they chemically convert in the atmosphere to form fine sulfate and nitrate particles. Power plants also emit fine carbon soot particles directly from their smokestacks, which may appear as a black plume leaving the stack. In 1999, power plants directly emitted nearly 300,000 tons of fine carbon soot particles.[16]

While the 1990 Clean Air Act Acid Rain Program (Title IV) had resulted in significant initial progress in reducing SO_2 emissions from power plants, those emissions have recently begun to rise. The National Emissions Trends Report shows that power plant SO_2 emissions crept upward every year since 1995, rising more than 10 percent.[17] Disturbingly, in 1998, power plants emitted 1.26 million more tons of SO_2 than they emitted in 1995.[18] Nitrogen oxide emissions from power plants have risen 44 percent since 1970.[19] Moreover, power plant NO_X, PM_{10}, and volatile organic emissions—all of which contribute to fine particle levels — have also crept up slightly over the past few years according to the 1998 EPA report.[20] Taken together, while these increases are not enormous, the data suggest poor progress in curbing power plant emissions.

Indeed, the largest share of power plant-derived fine particle pollution comes not from direct emissions but instead from the conversion of SO_2 and NO_X into fine particle sulfate and nitrate.[21] This impact is most pronounced in the mid-western United States – an area densely populated with coal-burning power plants – and in the eastern United States – areas downwind of the vast majority of the nation's coal-burning power plants.

Most of the sulfur dioxide pollution from power plants comes from burning coal.



ABT ASSOCIATES

PETER ALTMAN

Even before London's "killer fog" event, coal combustion was understood to be the principle source of airborne soot and fine particles. Most of the coal used in the U.S. today is burned by power plants for the production of electricity. Among power plants, the oldest coal-fired facilities produce the largest share of the particle-related air pollution. Just over half of all power plant boilers in the U.S. are fueled by coal. However, coal-burning power plants account for nearly 90 percent of the SO_2 emitted by all power plants.[22]

Because of the now obvious associations between health, fine particles, and coal-fired electric generation, health researchers have recently made preliminary estimates of the relative contribution of power plants to total deaths. Using rudimentary analysis, researchers at the Harvard School of Public Health have estimated that power plants are responsible for approximately 15,000 deaths per year (i.e., one-quarter of an assumed 60,000 fine particle related deaths per year).[23] Indeed, embedded in EPA's Regulatory Impact Analysis for the $PM_{2.5}$ fine particle health standard was the power sector's contribution to death and disease from particles in our air.[24] Similarly, in EPA's cost-benefit analysis of the Clean Air Act, health benefits associated with reductions in power plant-generated fine particle pollution provided strong justification for pollution control costs imposed by the Act.[25] A recent Harvard School of Public Health study of two coal-fired power plants in Massachusetts found that the fine particle pollution from these plants may be associated with over 100 deaths annually.[26]

Washington Must Act!

Despite steps underway to reduce power plant emissions, a major hurdle remains: to date, the vast majority of coal- and oil-fired power plants have circumvented the most protective air emissions standards required of modern power plants. When the Clean Air Act was amended in 1970 and 1977, it was assumed that many of the nation's older power plants would be retired and replaced by cleaner, new power plants and therefore should be exempt from the emission regulations governing new plants. However, for a variety of reasons, these plants have not retired. Because of this "grandfathering" loophole, coal-fired power plants are largely exempt from modern, state-of-the-art pollution control requirements. The vast majority of these plants fail to meet modern pollution standards for SO_2 and NO_x. This special treatment for "grandfathered" power plants permits these facilities to pollute at rates up to 10 times that of modern coal plants.

Polluting coal-fired power plants must be made to comply with modern emission control standards. In addition, the nation's power fleet should be held to nationwide caps on all four of the key power plant pollutants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Reducing power plant NO_X and SO_2 emissions by 75 percent from 1997 emissions levels will dramatically reduce fine particle pollution so we can all breathe easier. A 75 percent reduction is both necessary to protect our health, and is readily achievable. The death, hospitalizations and lost work time caused by fine particles from power plants can be reduced comprehensively only when the Clean Air Act's 30-year loophole for old dirty power plants is finally closed.

Based on the Abt Associates analysis and the robust health evidence it is based on, reducing power plant sulfur dioxide and nitrogen oxide emissions by 75 percent will save 18,000 lives ***every year***. Moreover, the technology for reducing these emissions exists today. There is no excuse for further delay. Protecting the health of our loved ones, both the old and the young, compels swift action to cut dramatically the death and disease visited upon Americans by these dirty, antiquated plants.

Federal legislation now pending would reduce particle-forming sulfur dioxide and nitrogen oxide emissions by 75 percent from 1997 levels and significantly reduce mercury, and carbon dioxide emissions. Recently, the Environment and Public Works Committee of the U.S. Senate began hearings on the issue of comprehensive power plant cleanup. Given the uncertainty facing the industry from the combination of future environmental requirements and the advent of electric industry deregulation, even some of the largest polluting power companies have called for comprehensive legislation to clearly spell out their air pollution reduction commitments into the foreseeable future. Clearly the time is ripe to save lives by cutting fine particle pollution from the electric power industry.

NATIONAL PARK SERVICE

Lawmakers must cut through the haze and deliver Americans cleaner air.

Beyond Any Reasonable Doubt

Health Research Links Fine Particles with Death and Disease

The health effects of fine particle soot have been suspected for centuries. Early records suggest that King Edward II of England in the 14th century, ordered people who fouled the air with coal smoke to be tortured. In the steel town of Donora, Pennsylvania, in October 1948, the air became so filled with pollution that people could not see across the street. About half of the population of 14,000 in the town became sick, 10 percent severely ill, and 20 deaths were attributed to the episode. In London, four years later, a deadly fog blanketed the Thames River valley when a temperature inversion trapped air pollution near ground level from December 5th to 9th. The smoke from London's industries, residential furnaces and fireplaces filled the air. By the end of the episode, the death toll climbed to over three thousand; a five-fold increase over the normal death rate.[27]

The political response to the London event was immediate and decisive — burning of soft coal was banned in central London and smokestacks and chimney heights were raised, thus sending the pollution elsewhere. As would be repeated in the United States in the ensuing decades, "dilution" was seen as the "solution to pollution." The assumption was that as the pollution dispersed over a wider area, the lower overall pollution levels would entail no adverse health effects.[28]

In the early 1970's, U.S. researchers established a statistically significant "association" between air pollution at then-current levels and death rates in a number of U.S. cities. However, these studies could not establish a cause-and-effect relationship because they did not control for a variety of other variables that could have explained the relationship. For example, seasonal variations might be indicative of the amount of time people spend indoors or the spread of infectious diseases. The state of the science in 1980 did not establish a sufficiently robust link between air pollution and death, but it suggested that detailed investigations of this relationship would be critical to improvements in public health.[29]

Since that time, there have been extensive animal and human tests on the health effects of breathing fine particles. These tests show that fine particles can harm the respiratory tract and cause cardiac failure and therefore may be responsible for significant effects on health.[30] But the conventional wisdom on air pollution's link to early death did not change until two landmark studies clearly established the link between particles and death by tracking many individuals over long time periods in different geographic areas.

• Harvard Six-Cities Study

In a 1993 article in the New England Journal of Medicine, researchers reported on a study that tracked over 8,000 people in the United States over a period of seventeen years in six cities, each characterized by a range of fine particle levels. After controlling for other factors (smoking status, body mass, occupational risks, etc.), they found the risk of death in highly polluted areas was 26 percent greater than in areas with the lowest pollution levels. The so-called Harvard "Six Cities" study also showed for the first time that there is a "linear" or straight line statistical increase in risk directly proportional to increased fine particle concentrations. This critical finding suggested that there is no safe level of fine particles to breathe.[31]

• American Cancer Society Study

In March 1995, a second landmark study was published supporting the conclusions of the Six Cities study. The American Cancer Society (ACS) study tracked over half a million adults in 151 different metropolitan areas for more than seven years. Detailed information was collected from study participants regarding their age, sex, weight, height, demographic characteristics, smoking history, alcohol use, occupational exposures, and other factors. The study found a 17 percent increase in mortality risk in areas with higher concentrations of fine particles. The investigators also found linkages between fine particles and total mortality and with cardiopulmonary disease. The researchers concluded that exposures to current levels of air pollution are shortening the lives of Americans by several years.[32]

In his book summarizing the body of evidence on fine particle health effects, Dr. John Spengler, Director of the Environmental Science and

EPA prepares stringent new clean air rules

USA TODAY

Nov. 22-24, 1996

The New York Times

June 28, 2000

Research Links Deaths With Pollutants

Study of U.S. Metropolitan Areas Points to Problem With Particle

The New York Times

May 12, 1996

Microscopic Killers

The New York Times

November 28, 1996

Administration Issues Its Proposal For Tightening of Air Standards

Engineering Program of the Harvard School of Public Health, concluded that the most obvious and direct interpretation of the data is that approximately four percent of the death rate in the U.S. can be attributed to air pollution. That figure is large (approximately 60,000 deaths per year) and exceeds a hundred-fold the sum total of all deaths caused by the other pollutants that the U.S. EPA regulates.[33]

Relying on these studies and others, in 1997 EPA issued new air quality standards for fine particles. Polluting industries immediately attacked the standards and the scientific studies underlying them as “junk science.” Industry critics claimed the results were likely the product of flawed statistical methodology, due to poorly controlled exposure data, or poorly controlled factors such as heat or smoking. Industry demanded the raw data be released to its paid consultants for reanalysis. However, because confidentiality and personal privacy were guaranteed to the study participants, the researchers could not agree to the requests. Instead, the researchers agreed to a third-party reanalysis by the Health Effects Institute, a non-profit organization, jointly funded by EPA and industry to be an independent and unbiased source of information on the health effects of major pollutants.

HEI Reanalysis Confirms Landmark Studies

The Health Effects Institute (HEI) reanalysis of the Six Cities and ACS studies was performed in two parts by Dr. Daniel Krewski of the University of Ottawa and Dr. Richard Burnett of Health Canada.[34] The first phase involved an intensive audit of data quality combined with an independent effort to replicate the results of the original studies using the same data and techniques. The second phase, released during the summer of 2000, focused on extensive testing of the sensitivity of the original findings to a variety of different statistical techniques and 30 different variables that industry claimed would explain the differences in mortality between the cities such as other pollutants, climate, and socio-economic factors. However, the reanalysis found that these factors made relatively little difference in the results — including the effects of temperature and smoking — with the exception of an association found between education level and relative risk of death (lower education levels were associated with higher risk).[35]

Most importantly, through its reanalysis HEI confirmed the conclusions of both studies. For the Harvard Six Cities Study, HEI found that the relative risk between Steubenville (most polluted) and Portage (least polluted) was 28 percent —two percent higher than the 26 percent in the original study. The HEI reanalysis of the ACS data found a relative risk of 14 percent higher in the most polluted city compared to the cleanest – somewhat smaller than the 18 percent that the investigators found in the original study. In its analysis for this study, Abt Associates employed the more conservative value from the reanalysis of the ACS study as the basis for the mortality estimates in the report. Thus, the reanalysis confirmed the science behind EPA’s new fine particle health standard and provided additional evidence linking fine particles at current levels to serious adverse health effects. In short, the reanalysis systematically dispelled each of the arguments leveled against the original studies.[36]

New Research Supports Association Between Particles and Death

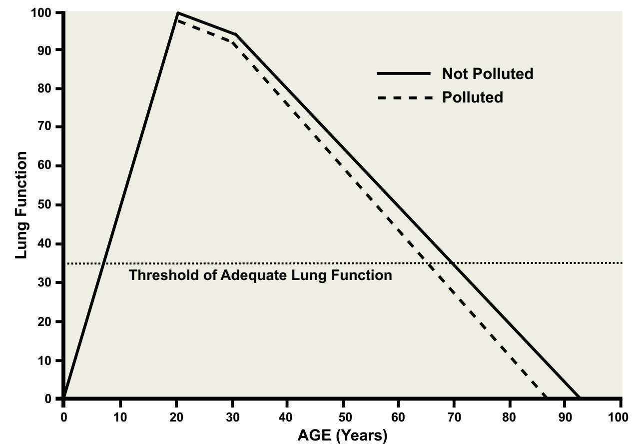
About the same time, HEI also released the results of a completely new study of acute mortality (deaths tracked daily with air pollution levels) in the 90 largest U.S. cities. In the study—the National Morbidity and Mortality Air Pollution Study (NMMAPS) — a team of investigators from Johns Hopkins University and the Harvard School of Public Health examined increases in daily mortality and hospitalization rates caused by short-term rises in particulate matter levels in the air. The investigators developed a new standardized methodology for examining pollution effects across many different U.S. cities including state-of-the-art statistical techniques to examine the effects of multiple pollutants and the extent that lives are being shortened.[37]

The National Morbidity and Mortality Study demonstrates the life shortening power of air pollution. Industry critics have long argued that the tens of thousands of deaths associated with particulate matter in these studies are, in their words, "insignificant." They claim the victims' lives are being shortened by only a few days because they were already near death and the rise in air pollution simply provided the fatal "last straw." Scientists euphemistically labeled this notion "harvesting."

NMMAPS categorically demonstrates that the concept of harvesting is incorrect. If the industry arguments were valid, then the death rate should fall below average as air pollution levels return to normal — following the "harvest" of frail individuals. But, in fact, just the opposite is true. Instead of a harvest, researchers observed that the death rate remains higher than normal for some time, lingering well beyond the time of the high air pollution episode and indicating that individuals weakened by the high air pollution levels continue to die for weeks or months following the air pollution event.[38] Moreover, recent analyses of chronic (i.e., long-term) exposure support the conclusion that life expectancy in more polluted areas is reduced by several years.[39]

Critics have also argued that other pollutants may be responsible for observed health effects and mortality attributed to fine particles. But, using new methods NMMAPS and the reanalysis carefully isolated the impact of particulate matter. In fact, NMMAPS found strong evidence linking daily increases in particle pollution to increases in death in the largest U.S. cities. The association between particulate matter and mortality persisted even when other pollutants were considered.[40]

Schematic of Lung Function vs. Age Showing Loss of Life Expectancy



Studies Link Fine Particles to a Range of Adverse Health Effects

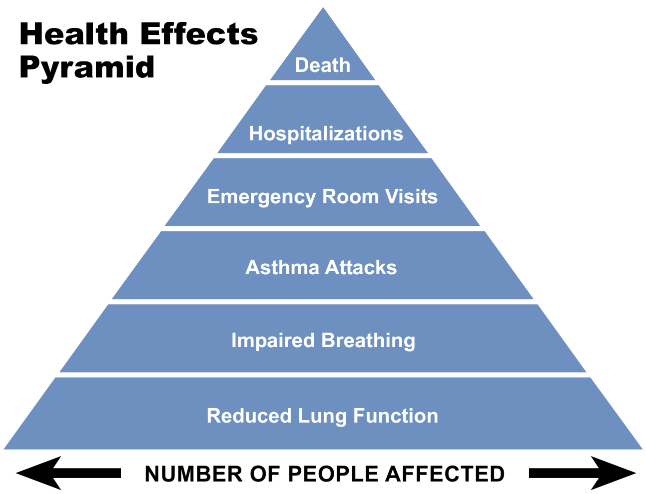
• Hospital Admissions

NMMAPS provides the best evidence to date for fine particles' link to a broad range of effects leading to hospitalization.[41] While previous studies established the link between fine particles and asthma-related hospital admissions, including a 1999 study which confirmed the relationship between increases in fine particle pollution and hospital admissions for asthma,[42] NMMAPS found robust associations between fine particle levels and increased hospital admissions for cardiovascular disease, pneumonia, and chronic obstructive pulmonary disease.

- ## Emergency Room Visits

Several other important studies also tie fine particle levels to emergency room visits. For example, fine particles were associated with emergency room visits for asthma in Seattle, Washington; Barcelona, Spain; and Steubenville, Ohio.[43] Studies have linked air pollution with both hospital admissions and emergency room visits. There is more data on hospital admissions that allows researchers to derive more complete estimates. Abt Associates based its emergency room visit estimates solely on asthma-related emergency room visits estimated in studies. Estimates of emergency room visits for other respiratory-related diagnoses must await additional studies. Thus, the estimate for asthma-related emergency room visits likely understates the total attributable to power plants.[44]

Health Effects Pyramid



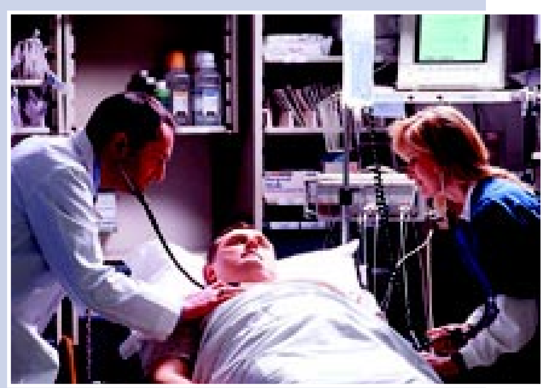
- ## Asthma Attacks

While these studies of hospital admissions and emergency room visits provide evidence that exposure to fine particles is directly associated with asthma attacks, researchers have also examined the relationship between air pollution and less severe asthma attacks that do not result in hospitalization. Studies in Denver, Los Angeles, and the Netherlands found that substantial increases in asthma attacks were linked with fine particle exposure.[45]

- ## Bronchitis

Several studies in the mid-1990's provide evidence that regular exposure to particle pollution over a number of years also gives rise to the development of chronic bronchitis.[46] These studies have been undertaken with groups of Seventh-Day Adventists, a religious order that forbids smoking, in order to control for smoking as a factor that could confound the health effects observed.[47]

New Research Links Fine Particle Pollution to Heart Attacks



Extensive new research published over the past year finds that fine particles at levels routinely found in many U.S. cities may trigger sudden deaths by changing heart rhythms in people with existing cardiac problems.[48] While further research is needed, these early studies are extremely important because cardiovascular disease is the number one killer in the United States, responsible for nearly half of all deaths. While heart rhythms in healthy persons remain largely unaffected by fine particle pollution, for those with existing heart disease fine particle exposures could have deadly consequences.[49] The threat seems particularly acute for elderly people who have existing heart arrhythmia—a life-threatening condition of rapid, skipped or premature beats—or the combination of a weak heart and lung disease such as asthma. The studies suggest that people are dying within 24 hours after elevated particulate matter exposures. About a dozen major scientific studies in the United States, recently completed or underway, are turning up evidence of heart pattern changes in animals exposed in laboratories and in elderly people tested in nursing homes.[50]

Similarly, a study of 13,000 children ages 8-12 found that higher levels of fine particle pollution were related to acute bronchitis.[51]

- Other Respiratory Symptoms

Many other studies have also found a link between fine particle pollution and a whole range of well-known upper and lower respiratory symptoms associated with air pollution including: deep, wet cough; running or stuffy nose; and burning, aching, or red eyes.[52] Associations between fine particles and more general measures of acute disease have also been found. For example, one study evaluated the impact of fine particle levels on lost work days from workers calling in sick,[53] an association that suggests an impact of air pollution on the U.S. economy, while other studies link particles and non-work restricted activity.[54]

How the Analysis was Performed

The Clean Air Task Force commissioned Abt Associates, the consulting firm relied upon by U.S. EPA to assess the health benefits of many of the agency's air regulatory programs, to quantify the power industry's share of the toll of death and disease from fine particles in the U.S. The objective of the study was to quantify the health impacts of fine particles from power plants, as well as the expected benefits (avoidable deaths, hospitalizations, etc.) of policies that would require all power plants to meet the same modern emission standards. For comparison, the study also estimated the health effects attributable to fine particle pollution from all diesel trucks, buses, locomotives, and construction equipment in the U.S. The health endpoints analyzed included death, hospitalizations, emergency room visits, asthma attacks, and a variety of lesser respiratory symptoms.

To analyze the avoidable health impacts of fine particles based on existing and hypothetical policy scenarios, the Clean Air Task Force asked Abt Associates to run three cases using methods developed for and employed by the U.S Environmental Protection Agency, extensively reviewed by EPA's Science Advisory Board, and accepted by the U.S. Office of Management and Budget in a variety of regulatory impact and assessment contexts.

In its analysis, Abt Associates assumed full implementation of the power industry's current air pollution reduction commitments, even though all of the required emission reductions have not yet occurred. The base case assumed full implementation of EPA's Summer Smog rule (i.e., the NO_x SIP Call) and implementation through 2007 of the Acid Rain program. Abt Associates analyzed the following scenarios:

1. Base case: full implementation to 2007 of the Acid Rain program (Phases 1 and 2) and EPA's Summer Smog rule (the NO_x SIP Call);
2. Base case in 2007 minus all power plant emissions — subtracting power plant emissions from the base case

Steps in the Analysis

gives us the health endpoints due solely to power plant emissions;

3. Base case in 2007 minus a 75 percent reduction in NO_X and SO_2 from 1997 levels.[55]

Abt Associates (health endpoint assessment and damage valuation) led the study team with support from ICF Consulting (power system economics and air quality modeling), and the E. H. Pechan (emissions and air quality modeling).

• Power System Economics

(ICF Consulting)

The first module of the model involves power system economics and asks the question: how will the power system respond to the imposition of the costs of cleanup? Possible compliance responses by the plants include reducing emissions through emission control equipment, obtaining emission reduction credits from other plants that "overcontrolled" their emissions relative to their required emission reduction levels, reduced utilization of the plant, or retirement and replacement with other sources of electricity. The analysis assumed that the power sector will meet the proposed pollution reduction goals in the most cost-effective manner available and provides critical information on the spatial distribution of power plant emissions before and after cleanup. ICF Consulting, EPA's power system modeling consultant, ran its Integrated Planning Model (IPM) to determine the spatial distribution of emissions under the various scenarios. In running the model, ICF Consulting used inputs and assumptions consistent with EPA's Clean Air Power Initiative (CAPI) modeling analysis and other recent regulatory impact work.

• Air Quality Modeling

(E. H. Pechan and ICF Consulting)

The outputs from the IPM provide the power plant emission inputs to the air quality modeling work performed by ICF and by Pechan. First, they assembled the emissions inventory for all non-power plant sources of NO_X, SO_2 and direct particulate emissions. Using the power plant emissions inputs from ICF Consulting, Pechan and ICF ran EPA's PM air quality models: Source-Receptor matrix (used to model the NO_X SIP Call and other regulatory actions) and Regional Emission Modeling System for Acidic Deposition (REMSAD) (approved by EPA's science advisory board and used in the Clean Air Act cost-benefit study). Both air quality models were used to estimate the baseline fine particle contributions attributable to the power plants and the reductions in pollutant concentrations due to the targeted reductions. The inputs and assumptions used by Pechan and ICF are consistent with recent projects performed by Pechan and by ICF for EPA, such as the regional NO_X rule (SIP Call), automobile emissions standards (Tier 2), and other similar analyses. The health effects estimates reported here are based on the REMSAD modeling outputs.

• Health Impacts Analysis

(Abt Associates)

The air pollution concentration outputs from ICF and Pechan's air quality analysis provided the inputs for Abt Associates' health effects modeling. Then utilizing health studies described above which link changes in ambient fine particle concentrations to changes in risk of mortality and morbidity, pollution concentration-response functions were derived that quantify the relationship between the forecasted changes in exposure and the expected changes in specific health effects. Abt Associates then used the modeled changes in pollutant concentrations (from the base case to the emission reduction scenarios) to estimate the power plant-attributable health impacts from each. The difference between the base case and the emission reduction scenario yielded estimates of the health benefits (or avoided adverse impacts).

Once the avoidable health impacts were determined, the monetary value of each of the various health endpoints was estimated through economic valuation techniques previously used in EPA analyses. Given the attributable and avoided health impacts calculated, Abt Associates tallied the health damages — from lost work and cost of emergency room care, to the statistical value of human lives lost from power plant emissions — and estimated the benefits of the health impacts avoided under the cleanup scenario. The methodology employed by Abt Associates was consistent with current and previous damage valuation work for EPA, and has been extensively reviewed by the EPA Science Advisory Board.

The full Abt Associates report is available at the Clear the Air website
www.cleartheair.org

The Policy Landscape

These compelling findings come at a time of growing public concern over power plant pollution. From Acid Rain, to summer smog, to the dirty haze that hangs over our national parks and wildlands, to the mercury contamination of the fish we eat, to the threat posed by global warming, power plants' contribution to a host of environmental ills is better understood than ever. No other single industry comes close to matching the variety and magnitude of public health and environmental impacts as those from electric power plants.

Fortunately, U.S. EPA and several states have begun to focus on mitigating the myriad problems of power plant pollution:

- This fall, states in the eastern U.S. are required by federal regulation to submit plans to significantly reduce by 2003-2004 their emissions that contribute to the problem of summer smog. The cornerstone of this requirement involves reductions in summertime emissions of smog-forming pollutants from power plants.
- EPA and the State of New York have launched enforcement actions against several power companies for violations of the federal law governing their emissions where it appears that for years these companies have made life-extending investments in old, dirty coal-fired plants without upgrading their pollution controls.
- By the end of 2000, the Administration has promised to propose regulations governing power plant emissions as they affect our national parks.
- Pending a Supreme Court decision to affirm the new fine particle health standard in the face of industry's challenge, states that violate the standard will be required to develop fine particle emissions reduction plans.
- New York, Connecticut, Texas and Massachusetts currently have regulations under development that could significantly reduce emissions from their power plants.

KAREN HADDEN

Most importantly, federal legislation now pending would reduce particle-forming sulfur dioxide and nitrogen oxide emissions by 75 percent from 1997 levels and significantly reduce mercury and carbon dioxide emissions. Recently, the Environment and Public Works Committee of the U.S. Senate began hearings on the issue of comprehensive power plant cleanup. Given the uncertainty facing the industry from the combination of future environmental requirements and the advent of electric industry deregulation, even some of the largest polluting power companies have called for comprehensive legislation to clearly spell out their air pollution reduction commitments into the foreseeable future.

Recommendations

Old Dirty Power Plants Must Reduce Fine Particle-Causing Emissions

Polluting coal-fired power plants must be made to comply with modern emissions control standards. In addition, the nation's power fleet should be held to nationwide caps on all four of the key power plant pollutants, including nitrogen oxides, sulfur dioxide, mercury and carbon dioxide. Reducing power plant NO_X and SO_2 emissions by 75 percent from 1997 emissions levels will dramatically reduce fine particle pollution so we can all breathe easier. A 75 percent reduction is necessary to protect our health and is readily achievable. The deaths, hospitalizations and lost work time caused by fine particles from power plants can be reduced comprehensively only when the Clean Air Act's 30-year loophole for old, dirty power plants is finally closed.

Requirements such as these can ensure that U.S. energy policy better accounts for the public health and environmental costs associated with electricity production and will propel us toward a more sustainable energy future that relies increasingly on renewable energy resources and conservation.

Now that policymakers know that simply cleaning up power plants to modern emission standards could save over 18,000 lives per year, there is no excuse for further delay. Protection of public health compels swift action to dramatically cut the death and disease visited upon Americans each year by these dirty, antiquated plants.

Simply cleaning up power plants to modern emission standards could save over 18,000 lives per year.

Endnotes

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Appendix

Health Effects from Power Plant Pollution by State

State	Mortality	Total Hospital-izations	Asthma ER Visits	Chronic Bronchitis	Asthma Attacks	Lost Work Days	Restricted Activity Days	Deaths per 100,000 adults
Alabama	1,110	701	246	627	20,600	173,000	886,000	42.8
Arizona	52	41	14	37	1,230	9,880	51,200	1.8
Arkansas	479	304	93	250	8,050	66,400	341,000	30.7
California	259	200	89	215	7,410	62,100	322,000	1.4
Colorado	64	48	22	56	1,800	16,000	82,800	2.5
Connecticut	299	213	71	197	6,040	52,800	271,000	15.4
Delaware	126	88	33	84	2,760	22,900	117,000	26.8
District of Columbia	118	64	23	60	1,900	17,500	89,900	41.3
Florida	1,740	1,350	342	1,010	30,800	245,000	1,260,000	17.1
Georgia	1,630	1,050	472	1,120	38,200	333,000	1,700,000	35.5
Idaho	8	6	2	6	192	1,530	7,950	1.0
Illinois	1,700	1,110	391	1,020	33,100	283,000	1,450,000	24.8
Indiana	1,030	679	244	623	20,500	173,000	886,000	30.0
Iowa	299	211	63	173	5,490	45,500	235,000	18.1
Kansas	274	185	62	163	5,300	44,600	230,000	16.7
Kentucky	997	635	229	578	19,000	161,000	819,000	44.1
Louisiana	481	291	118	284	9,800	81,900	422,000	20.1
Maine	55	36	12	34	1,060	9,090	46,900	7.3
Maryland	927	608	256	648	20,900	185,000	947,000	28.8
Massachusetts	441	313	104	283	8,880	78,000	401,000	12.3
Michigan	871	579	221	566	18,500	159,000	817,000	16.3
Minnesota	249	182	69	178	5,820	49,900	258,000	9.0
Mississippi	489	299	108	264	9,110	74,200	380,000	32.2
Missouri	896	569	184	494	15,800	133,000	684,000	28.5
Montana	6	4	1	4	116	954	4,950	1.0
Nebraska	122	84	28	73	2,390	19,900	103,000	12.5
Nevada	16	12	5	13	425	3,360	17,400	1.4
New Hampshire	67	46	18	48	1,540	13,500	69,800	9.3
New Jersey	1,100	758	259	708	21,900	189,000	967,000	21.9
New Mexico	23	17	7	17	599	4,880	25,300	2.1
New York	1,870	1,260	437	1,180	37,000	321,000	1,650,000	18.1
North Carolina	1,800	1,200	447	1,140	37,100	322,000	1,640,000	38.6
North Dakota	18	13	4	11	360	2,950	15,300	4.7
Ohio	1,920	1,250	442	1,150	37,100	313,000	1,600,000	29.7
Oklahoma	412	256	85	228	7,340	61,800	318,000	21.0
Oregon	43	31	11	29	912	7,740	40,100	2.0
Pennsylvania	2,250	1,510	445	1,240	38,400	318,000	1,620,000	32.0
Rhode Island	88	63	19	53	1,660	14,300	73,400	14.8
South Carolina	791	509	201	493	16,600	141,000	721,000	36.0
South Dakota	33	24	7	19	622	5,010	25,900	7.4
Tennessee	1,440	910	323	839	27,100	232,000	1,190,000	42.3
Texas	1,310	885	382	929	31,700	274,000	1,410,000	11.5
Utah	17	16	8	16	656	4,450	22,900	1.5
Vermont	32	22	8	22	692	6,030	31,100	8.6
Virginia	1,240	823	341	856	27,900	246,000	1,260,000	30.3
Washington	44	34	13	34	1,100	9,250	48,000	1.2
West Virginia	459	286	87	238	7,390	61,000	310,000	43.3
Wisconsin	448	317	109	288	9,340	79,300	409,000	14.6
Wyoming	7	5	2	5	183	1,490	7,710	2.3

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State	Mortality	Hospital-izations	Asthma ER Visits	Chronic Bronchitis	Total Asthma Attacks	Lost Work Days	Restricted Activity Days
Alabama	738	459	160	416	13,500	116,000	594,000
Arizona	11	8	3	8	251	2,150	11,200
Arkansas	277	174	53	144	4,610	38,400	198,000
California	49	36	15	38	1,280	11,200	58,400
Colorado	23	17	8	20	640	5,840	30,400
Connecticut	197	137	46	128	3,890	34,900	179,000
Delaware	80	53	20	51	1,640	14,600	74,900
District of Columbia	80	42	15	40	1,250	11,800	60,800
Florida	1,050	760	192	582	17,300	148,000	763,000
Georgia	1,090	688	309	747	25,200	223,000	1,140,000
Idaho	5	4	1	4	117	965	5,010
Illinois	981	635	222	589	19,000	164,000	848,000
Indiana	585	379	136	354	11,500	99,300	512,000
Iowa	183	128	38	106	3,330	27,800	144,000
Kansas	162	108	36	96	3,120	26,500	137,000
Kentucky	578	360	129	335	10,900	93,500	480,000
Louisiana	306	183	74	180	6,190	52,300	270,000
Maine	37	24	8	23	707	6,160	31,800
Maryland	619	397	166	428	13,700	124,000	638,000
Massachusetts	278	193	64	175	5,450	49,100	253,000
Michigan	523	343	131	338	11,000	95,600	493,000
Minnesota	153	111	42	108	3,530	30,600	159,000
Mississippi	318	192	69	171	5,880	48,400	249,000
Missouri	519	324	104	284	9,020	77,200	399,000
Montana	3	2	1	2	66	548	2,840
Nebraska	69	47	16	42	1,350	11,400	59,100
Nevada	5	3	1	3	109	982	5,110
New Hampshire	45	30	12	32	1,020	9,090	47,000
New Jersey	718	481	163	453	13,900	123,000	634,000
New Mexico	7	5	2	5	175	1,470	7,640
New York	1,200	792	273	744	23,200	206,000	1,060,000
North Carolina	1,190	771	287	744	24,000	213,000	1,100,000
North Dakota	10	7	2	6	207	1,730	8,950
Ohio	1,200	768	269	712	22,800	196,000	1,010,000
Oklahoma	250	154	51	138	4,420	37,500	194,000
Oregon	31	21	7	20	631	5,430	28,200
Pennsylvania	1,460	947	278	791	24,200	207,000	1,060,000
Rhode Island	57	40	12	34	1,060	9,380	48,300
South Carolina	515	324	127	318	10,600	91,900	472,000
South Dakota	19	14	4	11	354	2,880	14,900
Tennessee	857	533	188	500	15,900	139,000	715,000
Texas	805	534	229	565	19,100	168,000	868,000
Utah	7	6	3	6	246	1,900	9,820
Vermont	21	14	5	14	450	3,970	20,500
Virginia	828	542	223	571	18,400	166,000	855,000
Washington	31	23	9	23	744	6,390	33,200
West Virginia	296	181	55	153	4,700	39,700	203,000
Wisconsin	268	188	65	172	5,550	47,600	246,000
Wyoming	3	2	1	2	66	563	2,920

Health Effects from Power Plant Pollution Top 50 Metro Areas

State	Mortality	Total Hospital-izations	Asthma ER Visits	Chronic Bronchitis	Asthma Attacks	Lost Work Days	Restricted Activity Days
New York, NY	2,290	1,580	546	1,490	46,200	402,000	2,060,000
Washington, DC	1,140	764	354	881	28,600	257,000	1,320,000
Philadelphia, PA	997	654	225	593	19,000	158,000	808,000
Chicago, IL	995	648	256	651	21,400	186,000	957,000
Atlanta, GA	647	432	237	550	18,700	169,000	866,000
Pittsburgh, PA	585	395	105	309	9,210	75,500	385,000
Detroit, MI	527	343	134	343	11,200	96,400	496,000
St. Louis, MO	494	309	109	285	9,200	77,300	397,000
Tampa, FL	494	409	86	271	8,070	57,200	293,000
Boston, MA	454	320	113	302	9,540	84,000	432,000
Akron, OH	442	293	96	261	8,170	69,300	355,000
Cincinnati, OH	377	248	95	236	7,870	66,400	339,000
Dallas, TX	369	247	129	304	10,500	94,100	486,000
Greensboro, NC	309	210	77	201	6,380	56,000	286,000
Charlotte, SC	298	201	83	206	6,780	59,200	302,000
Nashville, TN	260	167	71	175	5,800	51,200	262,000
Birmingham, AL	257	164	57	148	4,760	40,200	205,000
Louisville, KY	256	162	59	152	4,870	41,200	210,000
Indianapolis, IN	250	161	64	161	5,300	45,400	233,000
Greenville, SC	226	148	54	139	4,520	39,100	200,000
Norfolk, VA	217	144	69	158	5,580	48,600	249,000
Richmond, VA	203	128	50	128	4,100	36,000	184,000
Columbus, OH	201	132	59	142	4,790	42,700	219,000
Houston, TX	201	132	76	178	6,140	54,400	281,000
Kansas City, MO	194	126	49	127	4,100	35,500	183,000
Knoxville, TN	190	130	44	118	3,730	32,200	164,000
Memphis, TN	185	107	46	110	3,780	32,500	167,000
Los Angeles, CA	184	143	65	156	5,440	45,400	236,000
Dayton, OH	181	115	42	109	3,520	30,300	155,000
Raleigh, NC	174	125	58	139	4,700	43,300	222,000
Milwaukee, WI	163	110	40	104	3,370	28,700	148,000
Chattanooga, TN	154	96	34	89	2,820	24,200	123,000
Johnson City, TN	154	98	30	84	2,580	22,200	113,000
New Orleans, LA	152	89	36	89	2,990	25,200	130,000
Orlando, FL	152	116	41	108	3,490	29,900	154,000
Buffalo, NY	149	98	29	82	2,530	21,400	110,000
Minneapolis, MN	135	99	45	113	3,750	33,200	172,000
Jacksonville, FL	131	84	35	87	2,910	24,500	126,000
Scranton, PA	122	79	19	57	1,680	13,700	69,700
Youngstown, OH	120	77	22	63	1,920	15,600	79,500
Harrisburg, PA	116	79	26	70	2,190	18,800	96,000
Augusta, GA	112	66	31	71	2,470	21,100	108,000
Hartford, CT	110	77	27	72	2,240	19,700	101,000
Tulsa, OK	108	68	27	69	2,230	19,300	99,300
Sarasota, FL	105	98	13	52	1,390	9,340	47,800
Lexington, KY	95	63	28	65	2,250	20,300	104,000
Allentown, PA	94	67	20	56	1,700	14,200	72,800
San Antonio, TX	93	67	29	69	2,410	20,500	106,000
Mobile, AL	92	61	22	56	1,860	15,300	78,600
Rochester, NY	90	62	23	59	1,900	16,300	84,000

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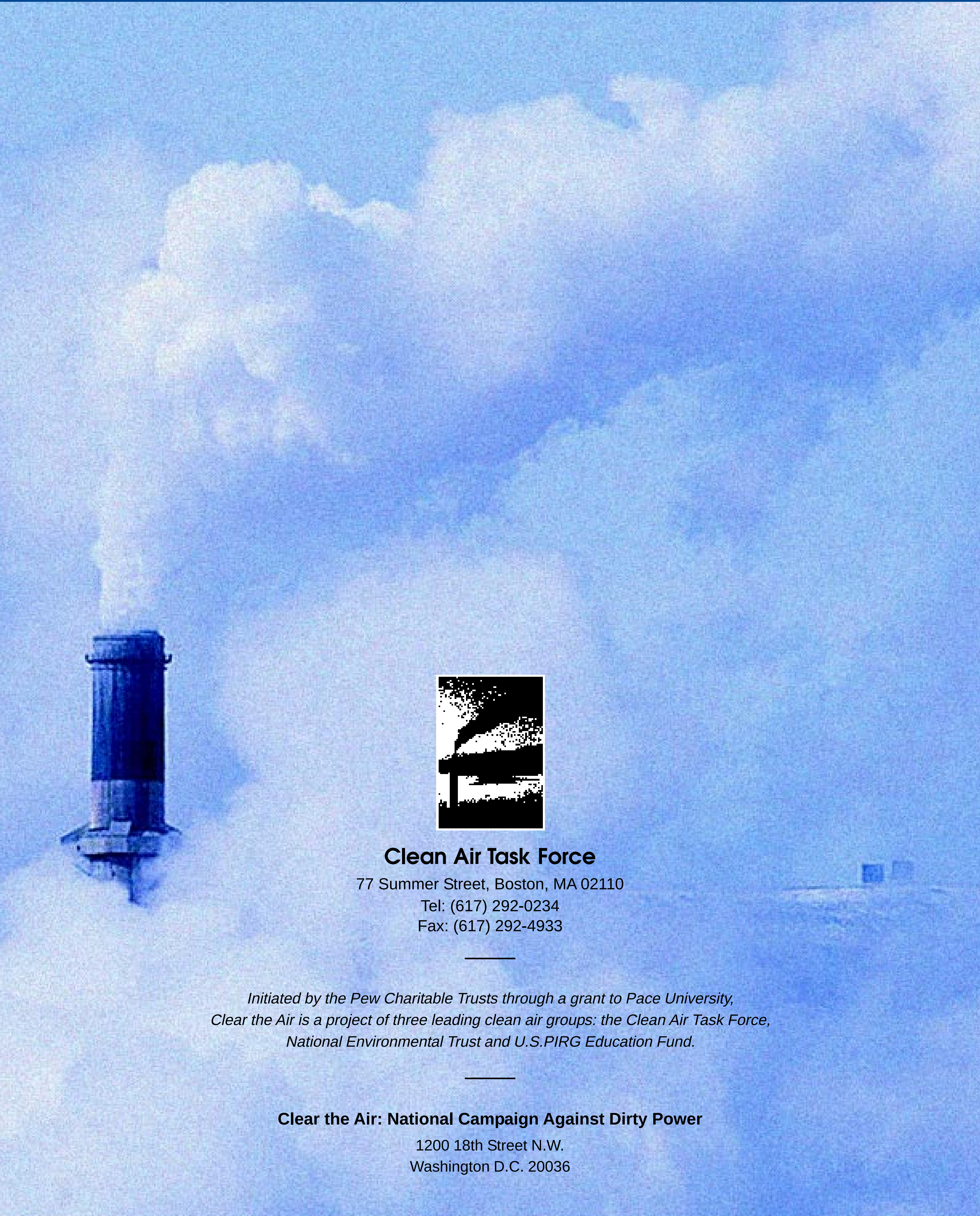
State	Mortality	Total Hospital-izations	Asthma ER Visits	Chronic Bronchitis	Asthma Attacks	Lost Work Days	Restricted Activity Days
New York, NY	1,470	991	341	945	29,000	259,000	1,330,000
Washington, DC	762	501	231	585	18,800	173,000	890,000
Philadelphia, PA	647	406	138	373	11,700	102,000	527,000
Chicago, IL	572	368	145	373	12,200	107,000	553,000
Atlanta, GA	431	283	154	366	12,300	113,000	581,000
Pittsburgh, PA	371	241	63	192	5,620	48,000	246,000
Detroit, MI	322	207	80	209	6,740	59,100	305,000
Tampa, FL	291	211	43	143	4,040	33,400	172,000
Boston, MA	287	198	69	188	5,880	53,200	274,000
Akron, OH	283	185	60	166	5,160	44,500	229,000
St. Louis, MO	280	170	59	159	5,060	43,900	227,000
Dallas, TX	228	151	78	187	6,390	58,200	302,000
Cincinnati, OH	223	144	55	139	4,590	39,500	203,000
Greensboro, NC	207	137	50	134	4,180	37,700	193,000
Charlotte, NC	191	125	51	131	4,240	37,900	194,000
Birmingham, AL	174	109	38	100	3,170	27,300	140,000
Norfolk, VA	150	97	46	107	3,750	33,600	173,000
Nashville, TN	149	95	40	101	3,300	29,600	152,000
Greenville, SC	145	93	34	89	2,860	25,200	129,000
Indianapolis, IN	145	91	36	92	3,000	26,500	137,000
Louisville, KY	145	89	32	85	2,690	23,400	120,000
Richmond, VA	138	85	33	86	2,730	24,600	126,000
Columbus, OH	128	83	37	90	3,020	27,400	141,000
Houston, TX	127	82	47	111	3,820	34,300	178,000
Raleigh, NC	118	82	38	93	3,120	29,400	151,000
Kansas City, MO	116	75	29	76	2,430	21,300	110,000
Knoxville, TN	114	76	26	70	2,200	19,400	99,800
Dayton, OH	109	68	25	65	2,090	18,300	94,200
Memphis, TN	109	62	27	65	2,210	19,200	99,100
Chattanooga, TN	100	61	21	57	1,800	15,700	80,400
Buffalo, NY	99	64	19	54	1,660	14,300	73,400
Milwaukee, WI	97	64	23	62	1,980	17,100	88,500
New Orleans, LA	97	56	22	56	1,890	16,100	83,400
Johnson City, TN	93	58	18	51	1,530	13,400	69,000
Orlando, FL	88	65	23	61	1,930	17,400	89,800
Minneapolis, MN	83	60	27	69	2,270	20,400	106,000
Scranton, PA	82	52	12	38	1,110	9,260	47,500
Youngstown, OH	78	49	14	40	1,220	10,200	52,200
Harrisburg, PA	76	51	16	46	1,410	12,400	63,500
Augusta, GA	74	43	20	47	1,620	14,000	72,100
Jacksonville, FL	74	46	19	47	1,560	13,900	71,800
Hartford, CT	72	49	17	46	1,430	12,900	66,400
Tulsa, OK	66	41	16	42	1,360	11,900	61,400
Sarasota, FL	64	54	7	30	758	5,720	29,500
Allentown, PA	63	43	13	37	1,100	9,490	48,700
Mobile, AL	61	40	14	37	1,220	10,200	52,600
Rochester, NY	59	40	14	38	1,220	10,700	55,200
Columbia, SC	56	36	17	41	1,400	12,800	66,000
Lexington, KY	56	36	16	38	1,300	11,900	61,300
Huntington, WV	55	32	10	28	871	7,450	38,100



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Initiated by the Pew Charitable Trusts through a grant to Pace University, Clear the Air is a project of three leading clean air groups: the Clean Air Task Force, National Environmental Trust and U.S.PIRG Education Fund.

Clear the Air: National Campaign Against Dirty Power

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KENTUCKY GOVERNOR'S OFFICE OF ENERGY POLICY

REPORT ON RATE DESIGN AND RATEMAKING ALTERNATIVES AS THEY IMPACT ENERGY EFFICIENCY

Technical Report

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INTRODUCTION

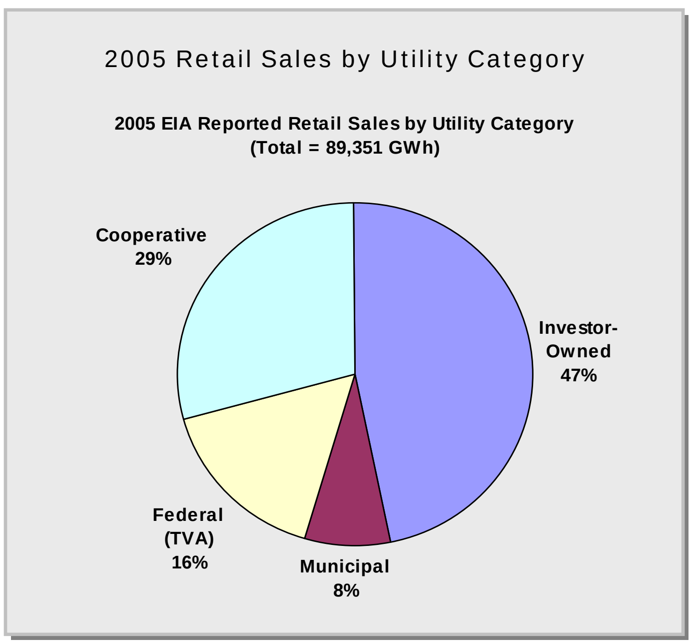
La Capra Associates was retained by the Kentucky Governor's Office of Energy Policy to conduct a study to determine the potential financial, social and economic impacts of alternative rate design structures and ratemaking methodologies that may encourage increased utilization of and investment in cost-effective energy efficiency and other demand response resources. This report is the implementation of Governor Ernie Fletcher's Executive Order 2006-1298, which called for the Office of Energy Policy to analyze the impact of incorporating energy efficiency as a goal of retail rate design. We interpret the purpose of this report as that of providing information to decision makers regarding how potential changes in rate design and ratemaking methodology may impact energy efficiency, utilities, and ratepayers in Kentucky.

The report is divided into two sections or tasks. The first section discusses alternative rate design structures and how they may impact energy usage in the state. The second section examines issues related to decoupling of rates and contrasts decoupling with alternative rate design. The specific tasks to be analyzed included:

1 A Analysis of Kentucky Rate Structures
1 B Review of Kentucky Electric Supply Cost
1 C Review of Alternative Rate Structures
1 D Analysis of Impact of Rate Structures on Energy Efficiency
2 A Review of Kentucky Ratemaking Methodology
2 B Assessment of the Benefits and Drawbacks of the Current Ratemaking Methods
2 C Alternative Ratemaking Methodologies
2 D How DSM Programs Can Be Implemented and Costs Recovered

Background

Kentucky electricity consumers, depending on service territory and customer type, are served by four different types of providers. Electricity providers include investor-owned utilities ("IOU"), electric cooperatives ("COOPs"), municipal utilities, and a federal power authority, Tennessee Valley Authority ("TVA").



Kentucky's four IOUs, Kentucky Power (American Electric Power), Kentucky Utilities ("KU"), Louisville Gas & Electric ("LG&E"), and Duke Energy are responsible for almost half of the retail sales of electricity in the state.

In addition to the four IOUs, two generation and transmission cooperatives ("G&T COOPs"), Big Rivers Electric Corporation and East Kentucky Power Cooperative, serve 19 rural electric cooperative corporations, which make up almost 30% of sales in the state. IOUs and COOPs are regulated by the Kentucky Public Service Commission ("PSC") in varying degrees. The remaining two types of service providers, municipals and TVA, are not regulated by the PSC. For purposes of this analysis, the focus will be on the regulated utilities and the load they serve.

Historically, Kentucky has been a low energy cost state. Its power supply depends heavily on relatively low-cost coal generation. Currently, more than 90% of energy produced in Kentucky is from coal, which keeps energy costs low. Also, much of the coal generating capacity is greater than 30 years old, which means that capacity costs are low due to depreciation of this capacity. As a result of the low electric rates, there has been less of an incentive in Kentucky to conserve energy and to invest in energy efficiency than in most areas of the country. Where customers are paying ten cents per kWh and greater, there is more incentive, than has existed in Kentucky, for customers and for utilities to institute measures that reduce electric usage

2005 Average Retail Rates

The estimated average total retail rates (based on retail sales revenues divided by retail sales) in Kentucky for 2005 were as follows:

Sectors	2005 State Average Electricity Rates (cents/kWh)
Residential	6.57
Commercial	6.01
Industrial	3.60
All Sectors	5.01

These rates are quite low compared to rates in most states across the country; however, this table understates current rate levels, as there have been significant rate increases since 2005. Fuel costs have increased, and in 2006, several Kentucky utilities (Duke Energy, EKPC, and Kentucky Power) received approvals for base rate increases of 7% to 21%, depending on the customer class.

However, Kentucky's electric industry is facing multiple challenges now and in the future. Recently, there have been dramatic increases in coal, gas, and oil fuel costs that have resulted in increased rates to IOU customers. Environmental regulations have caused and will cause additional upward pressure on rates. Cooperative utilities purchase much of their power, and their costs have increased because of higher, more volatile, market-based energy prices.

Going forward, the utilities are building a number of new coal generating units to meet fast growing demand. There is a PSC report that predicts that by 2025, Kentucky will need an additional 7000 MWs to meet the needs of a growing economy. New units will also be required to replace some older generating units. Investing in new generation will increase rates.

In addition to the impact that new generation will have on electric rates, it is likely that new environmental regulations will increase electric rates. For example, there is an increasing likelihood that some form of a federal greenhouse gas policy may take effect in the near term, which would significantly impact the cost of electricity from fossil fuel-based generation, especially coal. Additionally, federal policies are encouraging more efficient use of energy, since producing less energy is generally more environmentally benign than producing more energy.

For all of these reasons, the Governor and the GOEP are interested in how energy efficiency can be fostered in Kentucky. Kentucky's Energy Strategy includes among its recommendations the following:

- Maintain Kentucky's low-cost energy;
- Responsibly develop Kentucky's energy resources; and
- Preserve Kentucky's commitment to environmental quality.

Energy efficiency can be a major contributor to all of these objectives. How will such energy efficiency occur, and what energy policies will encourage energy efficiency? There are three basic possible sources that can improve energy efficiency: government actions; customer actions; and utility programs. The state can act directly to institute programs or building standards or tax incentives to encourage energy efficiency. State regulators can also influence customer actions through their regulation of rate design, and can influence utility programs through their ratemaking authority.

As a result of having low incentives to invest in energy efficiency in the past, there are many more opportunities for low-cost investments in energy efficiency than in states that have had high electric prices for years. In other words, there is likely a significant amount of low cost measures that can be instituted.

Energy Efficiency Terminology

Energy efficiency is sometimes thought of as measures that result in providing the same services with less energy. To be consistent with Kentucky's goal of maintaining low-cost energy, this report is using a somewhat broader definition, which is providing the same services at a lower energy cost. This encompasses both conservation and load shifting, which are defined below.

- **Conservation** of energy refers to reducing the amount of energy used. Lowering load across most hours reduces the need to build additional coal generation. Examples of actions that result in conserving energy include increasing the level of building insulation, and utilizing high efficiency lighting.
- **Load shifting** refers to shifting some energy from more expensive periods to less expensive. Load shifting reduces the need to build additional generation (typically gas-fired units) to meet peak load. Examples of devices that result in load shifting from peak hours to off-peak hours would include control devices on customer appliances and ice chillers, that use electricity during off-peak hours to make ice for air cooling.
- **Demand Side Management ("DSM")** refers to efforts to lower load and to shift load. Programs, run by utilities or by other entities, may encourage both types of change that should improve energy efficiency. Throughout this report, we will describe the energy efficiency programs run by utilities as DSM programs.
- **Demand response** refers to a change in load usage as a result of specific rates and by DSM programs; demand response is a substitute for supply resources.

TASK 1: ALTERNATIVE RATE DESIGN

Task 1A: Rate Structures

Before describing the electric rates that exist in Kentucky, we will provide a generic introduction to electric rate design.

Electricity Rates Primer

Electricity rates typically seen in customer bills are made up of three main components, along with riders and adjustments. The components and characteristics of rates are:

- **Customer charge** is a monthly charge which does not vary with usage and is same for all customers within rate group;
- **Demand charge** varies based on the greatest amount of energy used at one point in time in a month or peak usage in a month(also called a capacity charge);[1]
- **Energy charge**, measured in kilowatt-hours (kWh), is charged based on how much electricity a customer uses.

Rates are determined for customer groups that share similar characteristics, such as residential customers and different size (usually defined in terms of customer's peak load) commercial and industrial customers. Typically, a single rate is offered to each customer group. When energy charges do not vary by time[2], the signal to the customer is that the next kWh costs the same as the last. From an economics standpoint, the flat rate approach is inconsistent with how the cost of energy varies depending on a number of variables including the time of day, the season, and customers' individual peak demands. In a later section, we will discuss how alternative rate designs can reflect variation in the cost of electricity.

In addition to the basic rates, many utilities add on riders and adjustments to accomplish specific goals. Riders are additional charges that may be adjusted frequently, usually to track specified costs. Below, we discuss some of the riders in Kentucky that may impact customers' rates and usage.

- **Load Reduction Incentive Rider** is a rate offered to those with stand-by generating capacity that can be called upon when needed.
- **Fuel Clause Adjustment** permits the utility to adjust rates based on the cost of fuel. Since utilities have little control over fuel costs, this adjustment allows them to recover those costs without having to enter into costly and time consuming rate cases. [3]

[1] This requires a demand meter, so it is usually not applicable to small customers.
[2] This is described as a flat, nonseasonal rate.
[3] The fuel adjustor does not communicate monthly cost differentials accurately because of the lag in the collection of the change in costs.

- **The DSM Cost Recovery Mechanism**[4] allows utilities to recover direct program costs, to be compensated for lost revenue and to earn an incentive. This is calculated using a predefined formula.
- **The Environmental Surcharge** allows utilities to recover all costs associated with complying with environmental regulations applicable to coal combustion wastes and by-products that are not recovered in base rates, including a return on capital costs.

Representative Rate Structures in Kentucky

For analytical purposes of this report, we are focusing on IOUs and COOPs. They represent the majority of load in the state. In order to estimate the impact of potential rate changes on the State of Kentucky, La Capra Associates gathered a sampling of rates impacting major classes of the IOUs and of the COOPs. The customer classes examined were Residential, General Service (GS), Large Commercial and Industrial ("C&I"). Specifically, we reviewed the rates of Kentucky Utilities, Kentucky Power, and Blue Grass Energy, a distribution cooperative that is a member of the East Kentucky Power Cooperative, as representative of rate structures in Kentucky. Each utility offers slightly different rate structures.

Sample Rates for Kentucky Utilities fall 2007

Kentucky Utilities

Characteristic	Residential	General Service	Large C&I *(Primary)*	Large C&I Time-of-Day
Customer charge	$5.00	$10.00	$75.00	$120.00
Energy charge (per kWh)	$0.04865	$0.05818	$0.02501	$0.02501
Demand charge (per kW)			$6.81	On $5.16 Off $0.75
Fuel Adjustment (July) (per kWh)	$0.00947	$0.00947	$0.00947	$0.00947
Demand-Side Management Adjustment (per kWh)	$0.00122	$0.0014	-	-
Seasonality	None	None	None	None

4 The mechanism to recover revenues from IOU DSM programs is described in Appendix A.

Kentucky Power

Characteristic	Residential	Small General Service	Large C&I *(Primary)*	Large C&I Time-of-Day
Customer charge	$5.86	$11.50	$127.50	$276
Energy charge (per kWh)	$0.06002	$0.08824 first 500 $0.04805 over 500	$0.04415	$0.02044
Demand charge (per kW)		$3.36 plus $2.97 excess reactive	$3.36 plus $2.97 excess reactive	On $11.53 Off $ 3.31
Fuel Adjustment (July) (per kWh)	$0.00363	$0.00363	$0.00363	$0.00363
Demand-Side Management Adjustment (per kWh)	$0.000637	-	-	-
Seasonality	None	None	None	None

In developing representative IOU marginal electric rates below, we averaged the IOU rates by weighting these rates by sales by customer class. The customer charge is not included because it is not a marginal rate.

***IOU Average Marginal Electric Rate*[5]**

Characteristic	Residential	General Service	Large C&I *(Primary)*[6]
Energy charge (per kWh)	$0.05196	$0.0562	$0.03185
Demand charge (per kWh)	NA	$0.00181[7]	NA
Demand charge (per kW)	0	NA	$5.58
Fuel Adjustment (July) (per kWh)	$0.00777	$0.00832	$0.00738
Demand-Side Management Adjustment (per kWh)	$0.00087	$0.00112	$0
Total Marginal Cost to Consumer (per kWh)	$0.06059	$0.06744	$0.03924

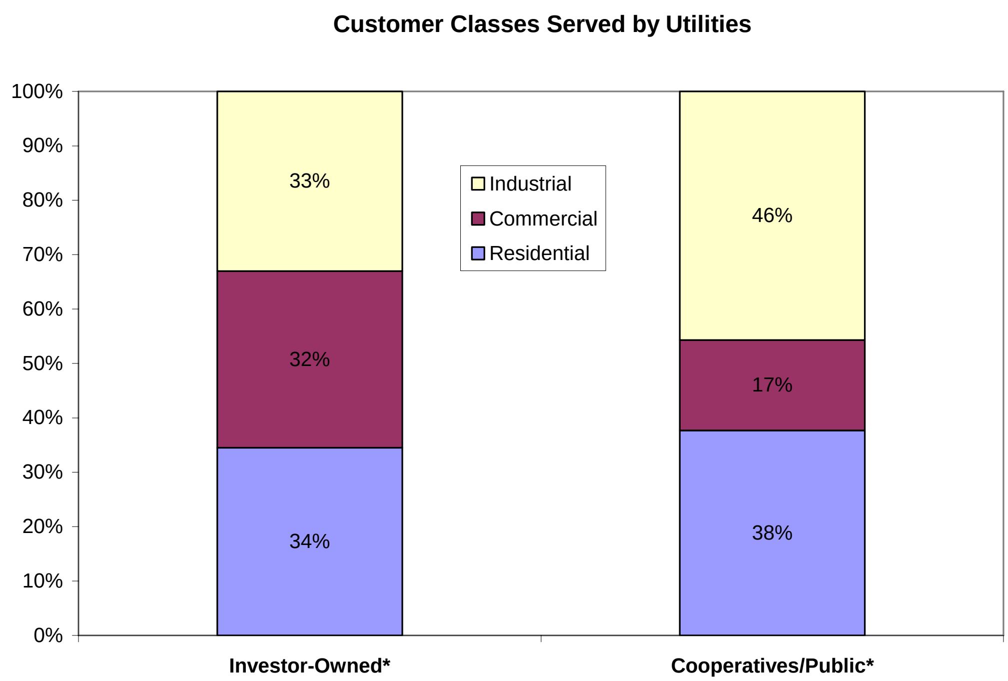
[5] Average marginal rates for the IOUs were calculated by taking a weighted average of the Kentucky Power and Kentucky Utilities rates.
[6] The large C&I average does not reflect the Time of Day rates.
[7] Since Kentucky Utilities does not apply a demand charge to smaller general service customers, we have estimated what energy rate the Kentucky Power demand charge to smaller general service customers is equivalent to. The estimate assumes a 50% load factor.

East Kentucky Power Cooperative – Blue Grass Energy

Characteristic	Residential	Small C&I	Large C&I [8]
Customer charge	$5.30	$6.95	$24.00
Energy charge (per kWh)	$0.06028	$0.06453 first 3,000 kWh $0.05973 over 3,000 kWh	$0.04945-1st 10,000 kWh $0.04275 – next 15,000 $0.03715 – next 50,000 $0.03485 – next 75,000 $0.03315 – over 150,000
Demand charge (per kW)		$6.23 over 10kW	$6.23
Fuel Adjustment (July) (per kWh)	$0.00583	$0.00583	$0.00583
Seasonality (per kW)	None	None	None

We utilize these actual sample rates to draw general conclusions about average IOU and COOP[9] rates throughout the state. Below is the customer break-down by customer classes of IOUs and COOPs in Kentucky.

Figure 1



**Estimates derived from 2005 EIA data.*

[8] The rate for large C&I customers here is represented by a declining block rate, where more usage results in lower unit rates.
[9] Blue Grass Energy Cooperative is assumed to be typical of the distribution cooperatives taking power from East Kentucky. The cooperatives that take power from Big Rivers Corporation serve primarily industrial load and are not reflected in this analysis.

TASK 1B: Kentucky Supply Cost

Electric Supply Cost Primer

There are a number of distinctions between electric costs that need to be clarified before discussing electric costs.

1) The first distinction is that separate costs can be identified for the supply (generation) function, the transmission function, and the distribution function. Since the primary goal of energy efficiency is its impact on the cost of supply, we focus on the cost of supply in this report.[10]

2) The second distinction is between energy and capacity costs. Energy costs are equivalent to variable costs (which vary with consumption) and capacity costs, (which do not vary in the short-run) are viewed as fixed costs because they typically reflect major capital investments.

> Marginal Costing Theory
>
> Marginal supply costs consist of short-run marginal energy costs and marginal capacity costs, which are added to marginal energy costs to measure long-run marginal costs. Short-run marginal energy costs are made up of the cost of fuel and variable O&M. When a customer uses an additional unit of energy, utility costs increase by the short-run marginal cost. The actual marginal energy cost for each particular utility will depend on its mix of generating sources. Marginal energy costs are normally higher than average energy cost. Marginal capacity costs reflect a longer run view: if load increases, additional capacity will be needed. Increases in peak load will require that the utility acquire more generating capacity, which gives rise to the marginal capacity cost.
>
> The marginal cost of capacity is usually considered to be the cost of the least-capital intensive technology, which, generally, is a Combustion Turbine.

3) The third distinction is between average and marginal costs. The average cost of supply is, as it sounds, the total cost of supply divided by the total quantity supplied. The marginal cost of supply is what it costs to produce an additional unit of supply. In the short-run, additional kilowatt-hours (kWhs) can be produced only by increasing production from existing generating units, so the short-run marginal cost is basically fuel. In the long-run, additional kWhs can be produced by building additional generating units. Marginal costs are crucial to providing customers with price signals. Only if prices[11] reflect marginal costs can customers make economically efficient decisions.

Average costs and marginal costs are related over time. If marginal costs are higher than average costs, average costs will be increase in the future as electric demand grows.

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[10] In the long-run there are also marginal transmission and distribution costs which may be avoided through either load reduction or load shifting. These tend to be small relative to marginal supply costs, and we are not addressing them.

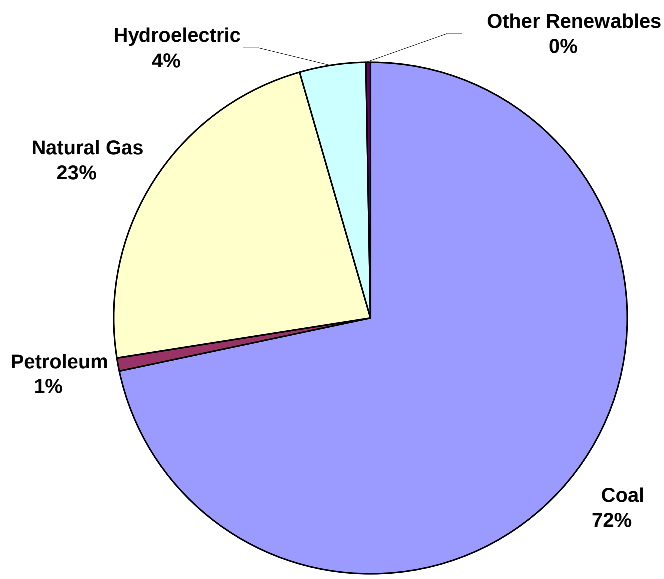
[11] The prices that should signal marginal costs are those that apply to incremental usage. Thus if all customers use 100 kWhs, the monthly customer charge and the price for the 1st 100 kWhs are not very relevant as price signals.

Average Cost of Electricity in Kentucky

Over 20,000 megawatts ("MW") of generation capacity are located in Kentucky, most of which are utility-owned, though some are owned by Independent Power Producers ("IPPs"). While 72% of the state's generation capacity is coal-based, these generate over 90% of the electricity produced in the state. Since 2000, more than 3,300 MWs of natural gas fired generation capacity have come on-line in the state, though some of this power is sold on the wholesale market.[12]

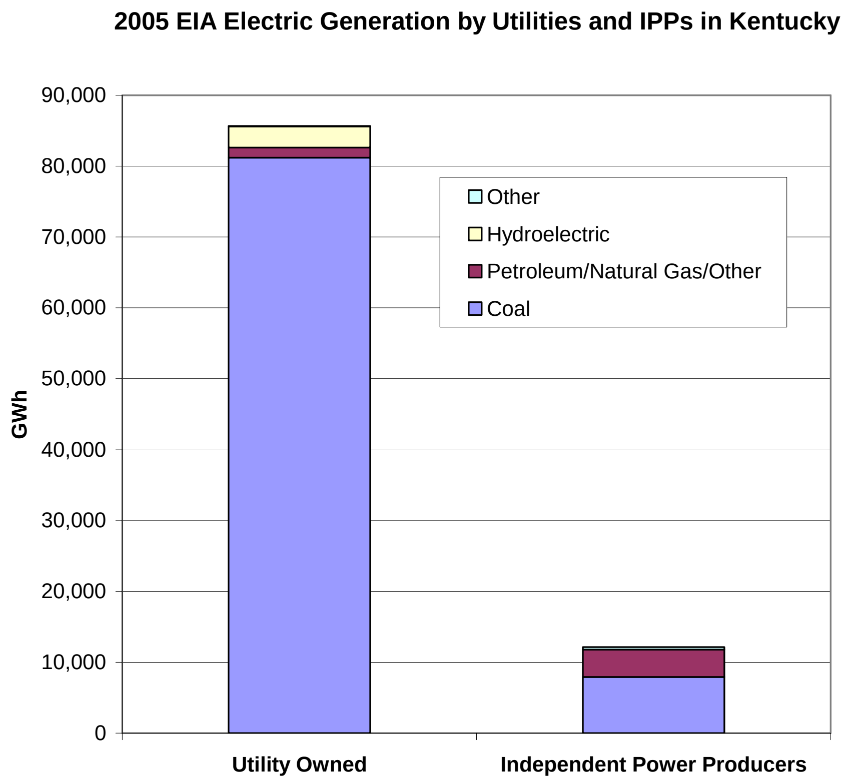
Figure 2

2005 EIA Reported Generation Capacity in Kentucky
(Total = 20,001 MW)



[12] No additional new power plants have been completed since 2005 in Kentucky. However, several projects are currently under construction.

Figure 3



Generating resources owned by IOUs provide most of the energy serving IOU load. Their average supply cost therefore consists of a return and depreciation on their generating plants and the fuel and operating and maintenance expense associated with these plants. The COOPs, however, purchase a larger proportion of the energy and capacity they use from third parties. This means that their average cost is more affected by market-based pricing, which is more volatile and which has been higher than the cost of owned generation in recent years.

It is important to note that one of the reasons that average electric rates in Kentucky have been low is that capital costs reflected in Kentucky rates have been low because many generating plants are more than thirty years old, and older plants are very heavily depreciated. Going forward, adding more capacity to meet growing loads will increase average rates; adding new capacity also to replace aging capacity will increase rates still further.

Marginal Cost of Electricity Supply in Kentucky

The cost that is most relevant to designing rates that provide appropriate price signals for energy efficiency is the long-run marginal cost of supply. The marginal cost of supply (also referred to as generation) includes the cost of additional energy (primarily fuel) and the cost of additional capacity. For customers to make efficient long-run decisions about appliance purchases and housing stock, they need to be able to compare the additional amount they will spend for the purchase with the savings in electric bills that will result from the purchase. They cannot make efficient decisions if rates do not provide them with price signals regarding future electric costs. Thus rates should include a reflection of marginal capacity costs. Other costs that should be considered are those that may result from federal action regarding environmental regulations. Federal, state, or local regulations regarding air emissions, water resources, land resources, and even aesthetics may all increase the cost of electricity. If the impact of likely and potential new regulations, particularly environmental regulations on Kentucky utilities is reflected in the utilities' projections of supply costs and of marginal costs, the next DSM screening analyses would find that many more energy efficiency measures would appear cost-effective and would pass the screening tests.

While concern has been focused on marginal supply (both energy and capacity) costs, increasing load will also increase transmission costs, as Kentucky's existing transmission facilities are heavily used. New transmission will have to be built to meet load growth. Building new transmission has become increasingly expensive and also difficult to site. We have included in our estimates of the cost of supply a very conservative estimate of the cost of additional transmission to deliver that supply.[13]

We expect that the marginal cost of supply is higher than average supply cost in Kentucky. This is true of the marginal cost of energy, as more than 90% of the energy is produced by coal baseload generation, but during some peak hours the marginal cost will most likely be determined by natural gas-fired generation. It is also true of the marginal cost of generating capacity. Adding new capacity is also much more expensive than the average capacity cost of existing generation, which as noted above has been significantly partially depreciated due to age. New generation capacity is more expensive than older generation. Moreover, the cost of building new generation has risen sharply in the last few years as a result of escalating material costs, a weakening U.S. dollar, and increasing labor costs. Based on the Handy Whitman Index©, a set of indices that track the cost of various generation components, the graph below shows that the cost of steam units increased by about 25% between 2004 and 2007.[14] Furthermore, gas turbine costs experienced an 18% increase just in the past year. The extent of future increases is difficult to estimate, but growth in global demand for materials will likely continue to put pressure on new generation costs. This translates to even higher marginal costs for new capacity than previously estimated by Kentucky utilities.

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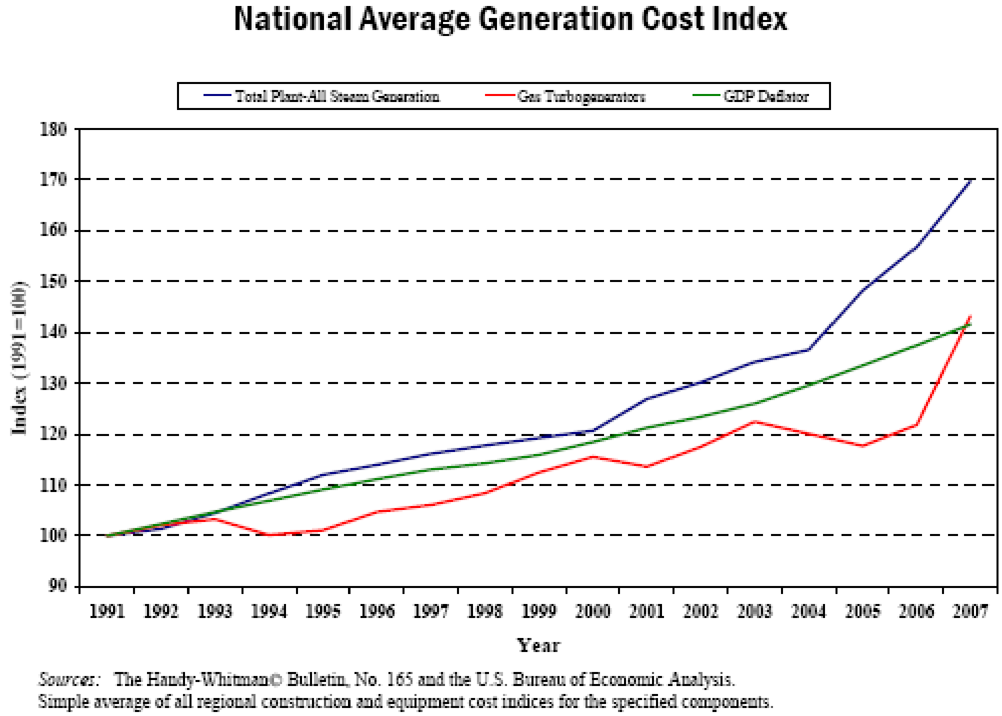
13 There are also marginal distribution costs, which we are not attempting to address, as they are very specific to the utility and local conditions.

14 Graph is an excerpt from "Rising Utility Construction Costs: Sources and Impacts," The Brattle Group, September 2007. <http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/rising_electricity_costs/Rising_Utility_Construction_Costs.pdf>

Figure 4



Excerpt from The Brattle Group

Some Kentucky utilities have plans in progress to build at least another 1300 MW of coal-based generation and about 200 MW of natural gas-fired combustion turbines in the next five years.[15] Furthermore, Kentucky Utility and Louisville Gas and Electric combined are also planning for more than 1000 MW of additional combustion turbines between 2013 and 2018 to meet future demand growth.[16] To the extent that the most recent DSM plans may expand DSM savings, forecasted needs may have decreased since these plans were offered.

Table 1: Utility Generation Under Construction or Planned

Unit Type	Plant/Unit Name	Capacity (MW)
Coal	Trimble County Coal Facility	750
Coal	Spurlock Unit #4	278
Coal	Smith Unit #1	278
Combustion Turbine	Smith Unit #8	100
Combustion Turbine	Smith Unit #9	100
Combustion Turbine	Misc. 2013-2018	1086

15 Coal Units: Trimble County Coal Facility (750 MW), Spurlock Unit #4 (278 MW) and Smith Unit #1 (278 MW). CT Units: Smith Units #8 (100 MW) and #9 (100 MW).
16 "Staff Report on the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utility Company," Kentucky Public Service Commission.

In estimating the marginal capacity cost of generation in Kentucky, we utilize the cost of a Combustion Turbine as indicative of the marginal cost of capacity.

The estimate of the marginal cost of energy used in this report is based on confidential data from a number of utilities. The same marginal cost for peak and off-peak hours in Kentucky is used for both IOUs and COOPs. The marginal cost of capacity is added to the marginal energy cost.

Impact of Environmental Policy on Electric Costs

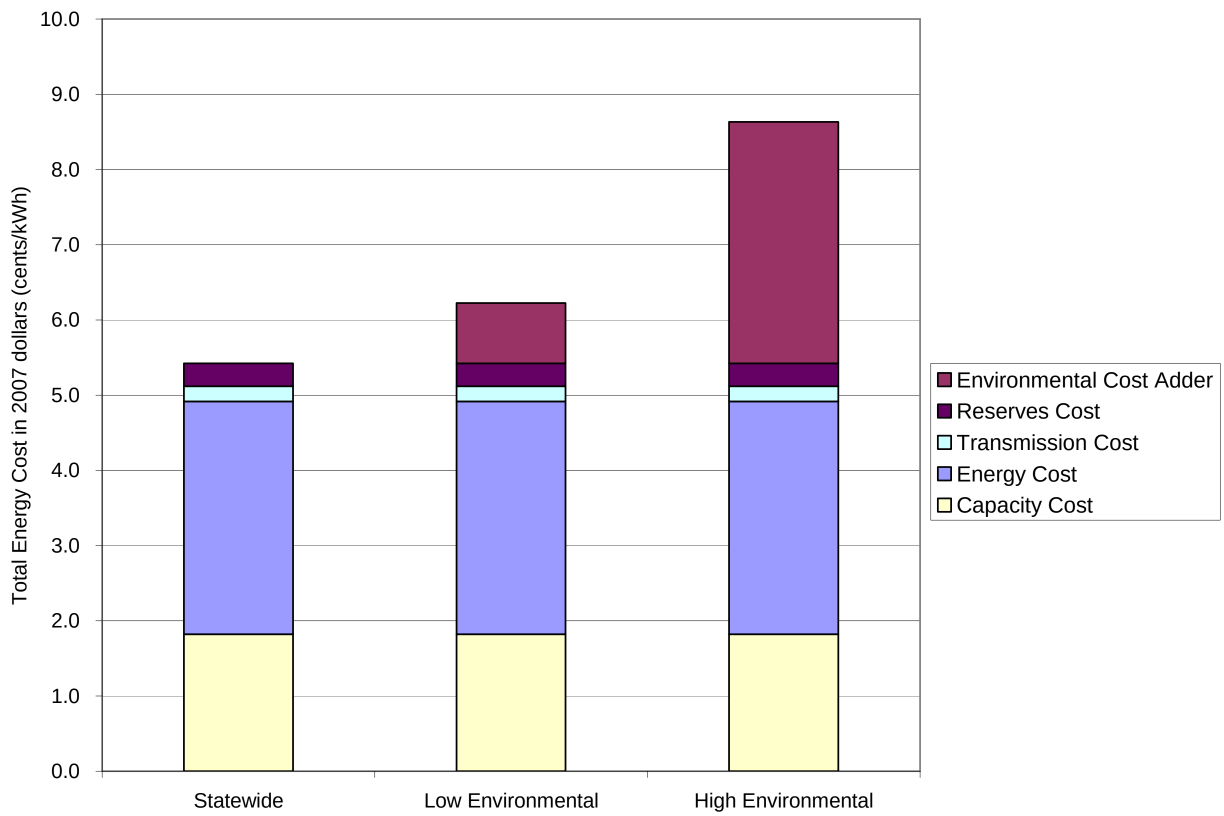
Looking forward, the potential for a federal climate change and greenhouse gas policy is increasing. There are a number of different proposals being presented in Congress, but all will significantly impact fossil-fuel based generation costs.[17] Other environmental concerns also may increase electric costs. We have made rough estimates of the potential cost of such regulations. There is a range from low to high cost. For the estimate of the potential rate impacts and the consequent change in energy and peak load, we have utilized the high estimate of the cost of environmental regulations (High Environmental).

Carbon Policy Cost

At least four different Greenhouse Gas Reduction Bills have been introduced in Congress this past year. While the ultimate goals differ, all the proposed legislation are relying on a cap-and-trade program with decreasing caps that will directly impact the electric industry. The programs' beginning year range from 2010 to 2012, with the latter being a more realistic timeframe to put appropriate rules in place. Previous studies of various bills show estimates of carbon costs ranging from about \$5 to \$25per ton of CO2 at the onset, but growing to about \$7 to \$50 per ton after 10 years (in 2005\$). In the graph below, we demonstrate the impact to Kentucky energy costs if carbon costs are \$10 and \$40 per ton for a representative year. This reflects a 15% to 65% increase in marginal cost of energy.

[17] "Climate Change: Greenhouse Gas Reduction Bills in the 110th Congress," CRS Report For Congress, January 31, 2007. <http://opencrs.cdt.org/rpts/RL33846_20070131.pdf>

Figure 5: Estimated 2012 Marginal Cost of Energy



Since the cost of electricity varies by season and by hour, and we want to examine the impact of seasonal and time-differentiated pricing, we present estimates of average state-wide rates based on marginal cost for a peak season[18] and for peak hours during the peak season. This enables us to estimate, in Task 1D, how much the current rates might change under different ratemaking structures.

[18] We assume that the peak season would be the three summer months for the IOUs , but would also include the three winter months for the COOPs.

Figure 6: High Season Marginal Cost Based Rate

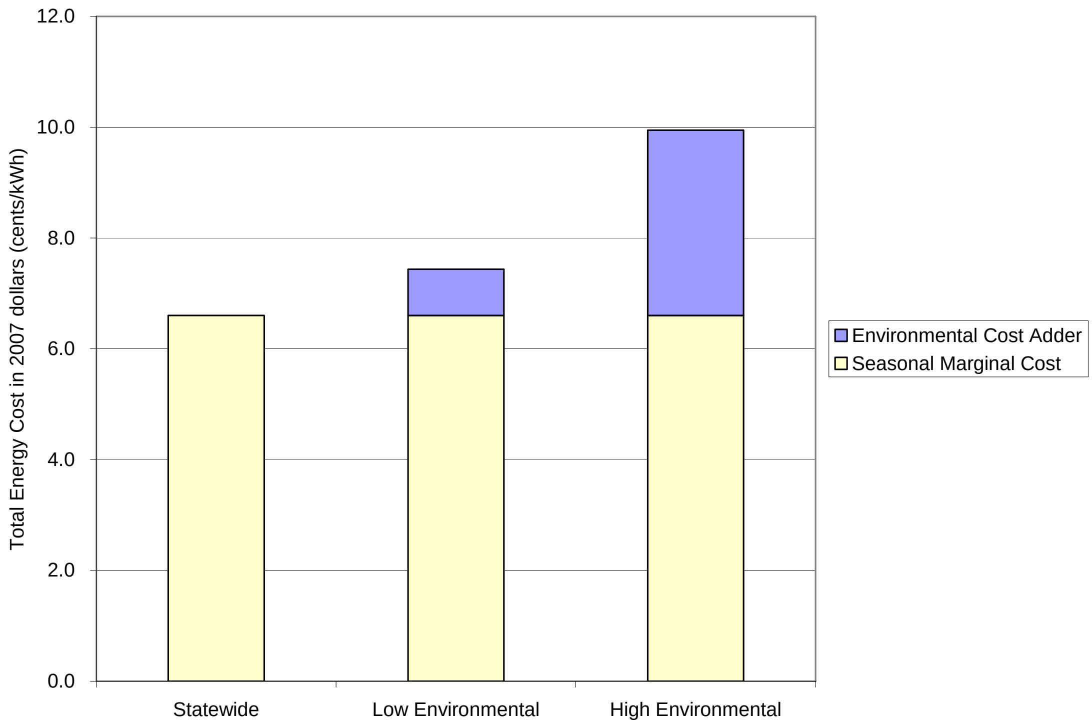
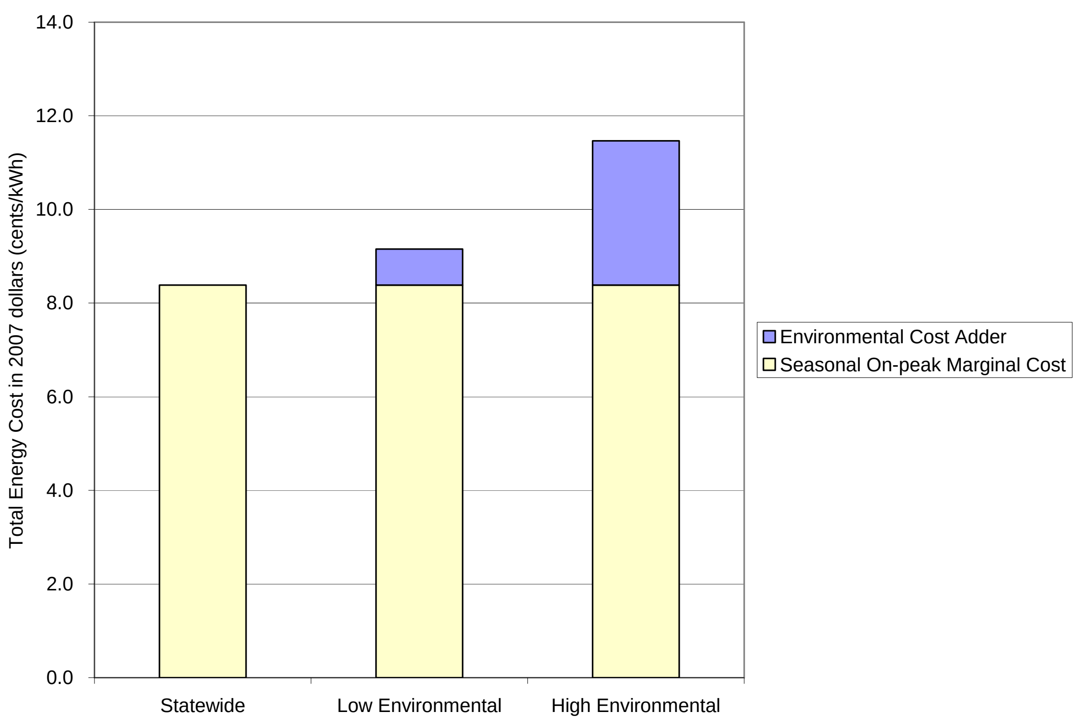


Figure 7: High Season Peak Period Marginal Cost Based Rate



TASK 1C: Alternative Rate Structures

There are alternatives to the standard rate structures described in Section 1 C that may provide more effective price signals in terms of encouraging additional energy efficiency. These are described below.

Seasonal Rates

A common variant to the standard rate structures are rates that vary by season. The seasonal differential is designed to reflect higher energy costs and/or higher capacity costs in certain seasons. Which months and seasons cost more and which less are determined by the utility's load shape and cost profile. Most commonly today, we find summer peaking systems driven by air conditioning. Energy costs tend to be higher in the summer. Since increases in the existing summer peak are likely the drivers behind any need for new capacity, summer capacity costs are also higher. There are some utilities that are winter peaking (driven by heating loads), and others whose winter and summer peaks are similar. Rate structures that reflect these seasonal differences inform customers that using power in the peak period is more expensive than at other times.

Increasing block rates

In this type of rate, customers pay one charge for usage (i.e., per kW or per kWh) up to some amount, and a higher charger for usage above that amount. The cutoff between the two rates is generally set at a number that results in most customers using more than the lower block amount. This enables the higher rate to be applied to the most discretionary (i.e., marginal) customer use. This rate may be useful in situations where the cost of additional output is greater than average cost (marginal cost is greater than average cost), such as when increasing use means the utility must use more of a more expensive fuel source. Increasing block rates are intended to let customers know that it is expensive to <u>increase</u> use, while not charging more than average cost for total use. It has been most common to utilize increasing blocks in energy charges, although the same concept can also be applied to demand charges.

> Declining Block Rates
>
> Earlier in the development of the electric industry, the more electricity that was generated, the lower the supply cost was per unit. Many utilities adopted a rate structure called declining block rates. With these rates, as the customer used more electricity, the price per unit would drop. Today, the marginal or next unit of energy that is purchased will cost more. Therefore, declining block rates can send a false signal to the market and discourage investment in energy efficiency. At least some cooperatives In Kentucky offer declining block rates for commercial and industrial customers.

Rate structures with more emphasis on demand

Rates structures in which much of the bill is collected through demand rates will create an incentive for customers to reduce their own peak use. Thus adding a demand charge to a rate, or increasing the amount charged for peak demand, will encourage customers to reduce their peak usage. However, only if customers' normal usage pattern is very coincident with the system pattern will these rates accomplish much in terms of limiting peak usage. There have been utilities that have voluntary or mandatory demand rates even for small customers. For instance, such rates have applied to residential electric heating customers in winter peaking systems. The theory would be that most residential customers turn up the heat at the same time and so drive the system peak; if residential heating customers reduce their peak load, they will probably also reduce the system peak. This rate is described primarily in the interests of completeness, as changes in metering costs make this alternative less reasonable today. For close to the same metering cost, utilities can install smarter meters, which can accomplish more than can simple demand meters. It would not be cost effective to introduce this rate design today.

Rate Structures to Further Demand Reduction

Some utilities offer curtailable and interruptible rates though contracts, usually to larger customers, in exchange for their willingness to decrease their demand when requested. Usually a penalty is established if the curtailment or interruption does not take place. These rates give utilities a way to manage loads during emergency situations. Such rates are increasingly being used to manage loads for economic reasons. The rates also allow businesses to benefit from the efficient operation of the overall system.

Most recently, with increased interest by consumers in building on-site generation (e.g. solar photovoltaic, wind, and combined heat and power systems), net metering has become a rate option available to consumers. Typically with net metering, customers who own generation receive a credit for a portion of the energy they produce in excess of their consumption, which can later be used to offset periods in which they are consuming in excess of on-site generation. In this way, their generation can help reduce the capacity and energy that a utility may have to provide to serve its load.

Time differentiated rates

Time differentiated rates will also further demand response. There are a number of ways in which rates can be differentiated by time of use. These rate forms have existed for at least 30 years, under the rubric of Time of Day ("TOD") or Time of Use ("TOU") rates. Time-differentiated rates charge different prices depending on time of usage; all true time differentiated rates require more than standard metering. These rates provide customers better information about the true cost of incremental usage. Better price

> **Example: Air Conditioning and TOD**
>
> For example, if a customer pays 7 cents per kWh for electric use, they will use air conditioning at any time when they want it cooler. If it costs them 14 cents per kWh from 9am to 8pm and 5 cents in other hours, they can cool more in the low-cost hours and less in the high-cost hours, or install equipment that will manage their air conditioning to reduce costs.

> **Example: Air Conditioning and Load**
>
> Consider the same air conditioning customer discussed above. If the high peak period is from 1 to 5 PM, cooling more before 1 in order to reduce air conditioning use is easier to accomplish than during the two-period example.

signals contribute to energy efficiency, as customers themselves can make better choices if they have better information. The federal Energy Policy Act of 2005 encourages states to consider instituting time-differentiated and other rates that can encourage demand response and reduce total energy costs. Kentucky IOUs have time-differentiated rates but only for large customers, and as noted later, they may not be priced appropriately. A number of states, particularly those with higher cost electricity, are moving toward rates for all classes that will further demand response.

There are a number of options for time-differentiation of rates, increasing in metering and administrative costs and in accuracy. These include:

- Differentiation of prices by fixed periods
- Critical Peak Pricing
- Real time pricing

> **Metering for TOU**
>
> Metering requirements for any time-differentiated pricing are more expensive than standard metering. However, in recent years the incremental cost has been falling. For non-demand meters, the cost is less than double the cost of non time-differentiated meters. Switching to time differentiated metering also requires changes in utility billing and record-keeping, usually requiring significant information system expense.

Most existing time differentiated rates only distinguish between a peak and an off-peak period, which have been determined by analysis either of the utility's costs or its load.[19] We might find that the average marginal cost in the peak period is higher than the average marginal cost in the off-peak period by about 3 cents/kWh. Typically, during the off-peak period hourly marginal costs are set by baseload resources and do not vary greatly. There is more variation in hourly marginal costs during the on-peak period. In summer peaking systems, there is usually a high peak period in the afternoon, which is driven by air conditioning load. If costs are calculated and rates charged separately for the high peak period, marginal costs in this period might be 6 cents higher than in the off-peak period and 2 cents higher than in the moderate peak period. This critical peak or super peak pricing creates both more incentive for customers to switch load, and more opportunity.

Many utilities have offered time of use rates to customers on a purely optional basis. Optional rates will tend to attract customers who already have more than the typical ratio of off-peak to peak usage. If the rate is voluntary, peak/off peak usage will be a result of this customer self-selection as well as load shifting from more expensive to less expensive periods. In other words, although customers on voluntary time differentiated rates may use a higher proportion of energy off-peak than other customers, this may not reflect a change in usage due to the rate. Mandatory time-of-use rates are likely to cause customers to deliberately shift load, especially large customers who have more load that can be shifted. Customers who use very little electricity will tend to have little ability to shift load, so one rate design alternative is to make time of use rates mandatory only for relatively large customers. In Connecticut, for instance, which is making a great push for

[19] There is usually a very high correlation between increases in load and increases in costs by hour.

demand response, utilities have been moving toward mandatory time of use rates, introducing them first to the largest customers.

KU and LG&E will be implementing a Responsive Pricing and Smart Metering pilot program (Case No. 2007-00117) for residential customers. This time-differentiated pilot rate should provide information about how Kentucky-specific residential customers will respond to rate structures that better reflect marginal costs.

Real Time Pricing

Real Time, or dynamic pricing, informs customers of actual costs, usually on an hourly basis. Real time pricing should provide the most accurate price signal to customers, but it is also most complicated to implement and to communicate. There are very large customers who are and have been receiving either day ahead hourly prices or real-time prices and who can respond to these prices. Other means of providing information about real-time prices are provision of temperature data in areas that are very weather sensitive or signals which inform customers when prices are expected to be above some threshold level. Real-time pricing is most relevant in areas where hourly prices are determined by regional power markets with transparent electricity pricing, which may occasionally result in peak prices of $2.50 per kWh and more. Real time pricing is probably not appropriate for Kentucky's system.

TASK 1D: Impact of Rate Structure on Energy Efficiency

Comparison and Evaluation of Rate Structures relative to Energy Efficiency

This task is aimed at answering the question of whether existing rate designs in Kentucky communicate appropriate price signals to incentivize customers to make cost effective energy efficiency choices, and at the impact that changes in rate structures is likely to have on electric usage in Kentucky. The analyses of changes in usage are based on aggregate data and are necessarily not precise.

Existing flat rate structure

The first question is whether the existing flat rate structure charges at least as much as average marginal supply costs. Based on a comparison of our estimates of marginal costs to residential rates[20], the existing flat rates appear to be somewhat higher than average marginal supply costs. This is not surprising, since average rates recovery distribution costs as well as supply costs.

The second question is how flat rates will affect customer demand and energy efficiency when increases in fuel costs, capacity costs, and possibly costs resulting from carbon policy are included in rates. The existing rate levels and rate structures have been based on conditions that existed in the past, conditions that are changing.[21] If rate increases are greater than the rate of inflation (i.e. there is a real increase in the price of elasticity), this will have some dampening effect on electric demand.

> If marginal costs increase, block rates might improve current rate design
>
> Another question is whether these cost increases will cause marginal costs to rise more than average costs. If marginal supply costs are or become higher than the total average per kWh charge, flat rates will not signal to customers the marginal cost of supply. Rates could theoretically be redesigned to communicate the higher marginal supply costs. For instance, the introduction of an increasing energy block rate, as described in Section 1C, would communicate that higher usage cost more than average cost. This rate change should lead to somewhat more demand response than a simple increase in flat rates.

Alternative rate designs can improve price signals and energy efficiency

Even though current total rates appear to be as high as average marginal costs, this does not mean that current rates are providing appropriate price signals to encourage cost-effective energy efficiency. Rate design could do a much better job than the current rate structure in providing price signals regarding the cost of producing electricity. Fundamentally, marginal costs vary across months and across hours. An increase in load on a summer afternoon contributes to need

[20] Analysis of general service customers is much more complicated, and has not been performed.
[21] As an example of large changes in cost, LG&E & KU's Integrated Resource Plan of 2005 assumed price of oil was "…expected to remain below $30 per barrel until 2010" (Staff Report on 2005 IRP in Case No. 2005-00162, p. 4)

for new capacity and causes expensive fuel to be burned. An increase in load in the night in a mild spring month does neither. Flat rates do not communicate this and therefore do not provide customers with the opportunity to respond to underlying marginal costs.

Increasing block rates

For many rate classes, energy use above a base amount is likely to be primarily during peak periods. For instance, high residential use in the summer will tend to reflect air conditioning. If this is the case, one simple substitute for a time-of-use rate is an increasing block rate, whereby customers pay more for use above some base amount.

Seasonal rates

The potential of this alternative rate design is discussed next, because it is relatively simple and does not require any metering changes. As described in Subtask 1A, there is essentially no seasonal differentiation in typical Kentucky electric rates and the only time-differentiated rates are voluntary rates which serve only very large industrial customers. Theoretically, this suggests that the existing rate structure is not communicating to customers the true cost of how they consume electricity.

Seasonal but non-time differentiated rates could provide better price signals than existing rates. Introducing seasonal rates would be a relatively simple matter, since it does not require any change in existing metering. The expected result would be some reduction in use during peak period use, but no load shifting within daily periods. We would expect limited shifting between periods in the short run. Customers might turn down the air conditioning or the heating[22], but could do little else to reduce load during the expensive periods in the short run. In the longer run, seasonally differentiated rates will provide more incentive to purchase more efficient space conditioning equipment.

Seasonal rates for the IOUs should probably look different than for the COOPs, due to different load shapes, which are summarized below.

In general, the load patterns for the IOUs tend to be summer peaking; both demand and monthly consumption are greatest in the summer months. On the other hand, the COOPs' peak demands and monthly consumption are slightly higher in winter than in summer. We understand this reflects a higher proportion of air conditioning in the more urban and suburban areas served by the IOUs, and a higher proportion of heating load in the rural areas served by the COOPs.

These load shapes[23] illustrated in the figures below indicate that while summer rates should be higher than rates during the rest of the year for the IOUs, the picture is more complicated for the COOPs. Their peak period includes three summer and three winter months.

[22] This response is obviously limited, as it will tend to decrease comfort levels. As noted in the discussion of elasticity, seasonal rate changes will probably not affect the usage patterns of very small customers and high income customers.
[23] Variability in load shapes is not identical as variability in marginal cost, but they are usually highly correlated.

Figure 8

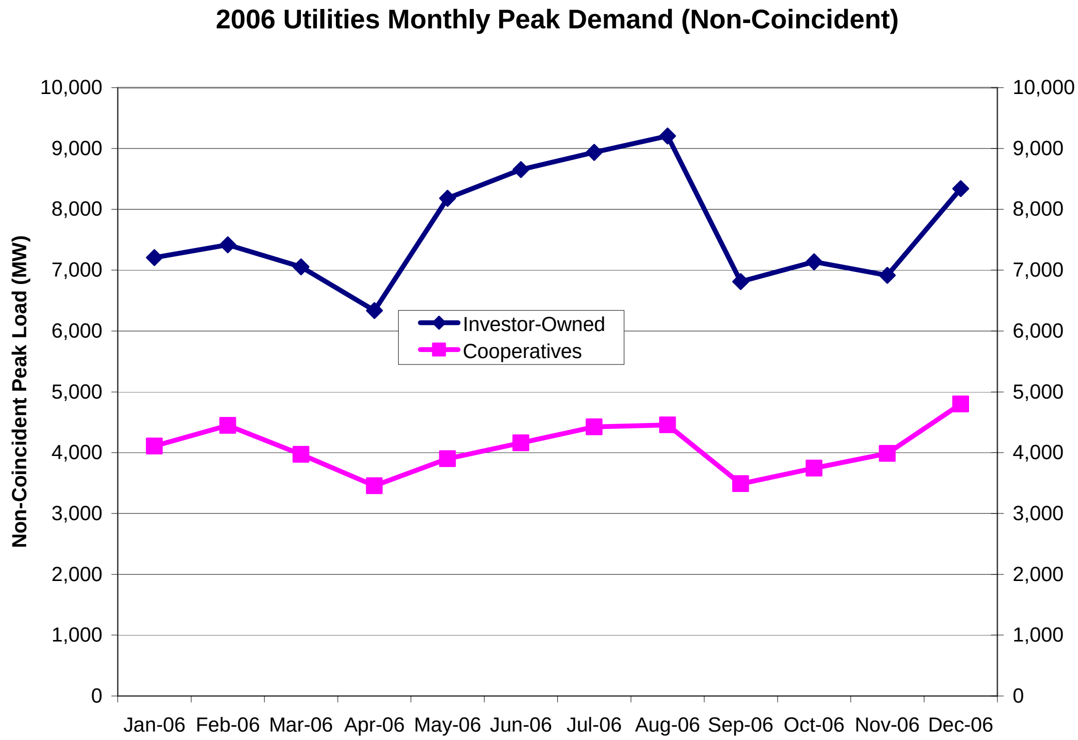
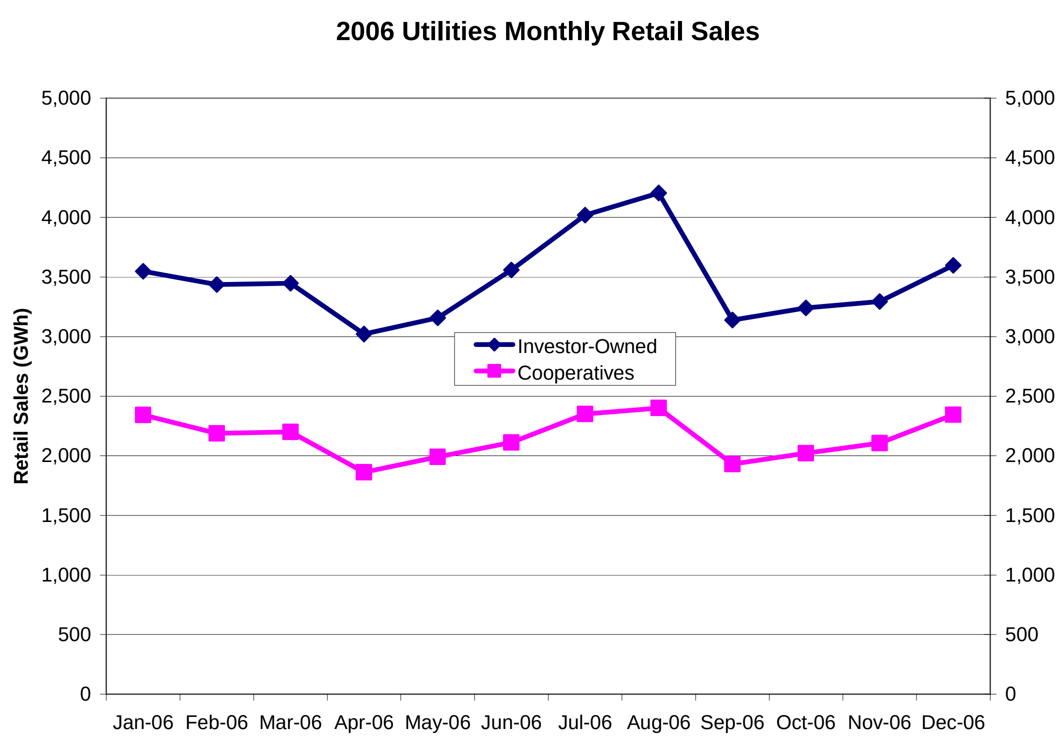


Figure 9



Time-Differentiated rates

Time-differentiated rates can provide the most effective price signals, although they introduce more expense and complexity. They can be expected to improve the efficiency of use of the electric system by informing customers of the different marginal costs at different times. Many customers will respond, both in the short and the long run, by shifting load from more expensive to less expensive times.

> **Issues Related to TOU Rates**
>
> Introducing mandatory time-of-use rates raises a number of issues. The additional cost of metering must be considered and weighed against the potential savings in electric supply costs that can be caused by the rate change. In addition, there may be concerns about the bill impacts that could result from mandatory time-of-use rates. Time differentiation will increase some bills more than others, perhaps significantly so. Policy makers must make policy decisions between better price signals and bill continuity.

We have performed a number of analyses to estimate the impact that alternative rate designs could have on energy efficiency – both in terms of reducing load and of shifting load from more expensive period.

Modification to existing Time-Differentiated rates

It was noted that the IOUs offer time-differentiated rates to larger customers. A fairly large amount of general service load is served on these rates. However, it appears that these rates understate even current on-peak marginal energy costs. The time-differentiation exists entirely in the demand charge. This should provide an incentive to customers to manage their peak load, but the energy charge appears to understate current on-peak marginal energy costs. A redesign of these rates may have the potential to induce more energy efficiency. One caveat is that research shows that industrial loads can have very low price elasticities, so the impact of price changes may be small.

Analysis of the Impact of Possible Rate Design Changes

Rate design has the potential to reduce load growth and to reduce peak loads. Customer response to rates can reduce the need for additional generation.[24] This analysis begins with a comparison of existing average rates for the major rate classes to estimated marginal costs. Marginal costs are portrayed on an (1) average annual basis; (2) on a seasonal basis; and (3) on a time-differentiated and seasonal basis.

It is one of the axioms of economics that the quantity demanded of a product normally changes inversely with change in real[25] price. That is, for most products, as price goes up, the quantity demanded goes down. This response will usually be greater the more time customers have to adjust to the change. This response is called price elasticity. For goods that are considered necessities, as electricity is in the U.S., price elasticities are relatively low. That means that if

[24] This customer behavior is called "Demand Response".
[25] Price adjusted for inflation; the price of the good or service compared to the price of average goods and services. Through the rest of this discussion, "price" refers to real price.

prices increase by 10%, the decrease in quantity demand is less than 10%, particularly in the short-run.

The first step in the analysis is to suggest what rates would be if based on alternative portrayals of marginal costs. We have modified full marginal cost rates to reflect the likely impact of revenue collection constraints.[26] The second step is to estimate the impact on electric use of changes in rates, based on expected price elasticities.

We focus on two types of price elasticity —"own price elasticity" and "elasticity of substitution". The relationship between a change in the average price of electricity and the amount demanded is called "own price elasticity". This is due to customers using less electric service, and, in the longer run, customers reducing usage through measures such as purchasing more efficient appliances. Another type of elasticity is "elasticity of substitution". This type of elasticity estimates the relationship between an increase in price in some hours and a decrease in price in other hours on the use in those periods. This involves customers shifting use of appliances from the high cost hours to the lower cost hours. There has been a great deal of recent research on price elasticity with regard to electricity, and we have relied on that research.

> **How the elasticity calculation works**
>
> Suppose that price elasticity for a product = (-0.5). Some individual customers will respond more , and some less, but this represents the typical customer price elasticity. If the price of the product increases by 50%, we multiply the elasticity times the percentage price increase – and find that customers in general are expected to purchase 25% less of the product because of this increase. .

Our estimate of marginal cost shows that a environmental regulations could increase marginal costs significantly. It would also cause a lesser increase in average costs. Communicating the marginal cost to customers would probably require adoption of an increasing block rate.[27]

We have made rough estimates of the impact of seasonal rates on energy consumed by the residential class during the seasonal peak period (all-hours during peak months) and of the impact on peak usage. Under this rate, customers pay somewhat more for energy during the peak season for the IOUs or seasons for the COOPs.

> **Estimates of Residential Price Elasticity**
>
> Based on the average of 58 recent studies of "own-price elasticities" in California and in the U.S., the short-term elasticity was estimated to be (-0.12) and the medium-term elasticity was (-0.28). This means that a 50% increase in rates, for example, may decrease consumption 6% in the short-term and 14% in the medium-term.
>
> Estimates of residential "elasticity of substitution" range from (-0.1) to (-0.19) derived from 14 different experiments, with a pooled estimate of (-0.13). This would imply, for example, if rates were 50% higher during on-peak hours, there would be a shift of 6.5% of usage during on-peak hours to off-peak hours.
>
> To be conservative in this analysis, we have assumed an own price elasticity of (-0.12) and an elasticity of substitution of (-.13).

[26] By this we mean that flat rates set to equal estimates of marginal costs might cause non-peak monthly rates and off-peak hourly rates to decrease so much that the utility could not collect full revenues. We have accordingly moderated the full marginal cost rates where necessary.
[27] Because if the marginal cost were charged to all usage, the utility would over-collect its revenue requirement.

We have also estimated the impact on system peak load of a rate that is both time-of-day and seasonal rate for residential customers. Under this rate, customers pay an even higher rate for use during peak hours in the peak season. It is more difficult to estimate the impact of time-of-day rates for commercial and industrial customers, as there is a wider range of elasticity estimates, and as some of these customers are already served on time-of-day rates.

Residential Results

We have estimated the potential impact on residential load of various types of rate changes. Seasonal rates, based on seasonal marginal costs, will result in reduction of load during peak seasonal periods. Time-differentiated rates will reflect even higher marginal costs during peak hours. This will result in shifting of load from more expensive periods to less expensive periods, and will probably also cause a reduction in total load. Higher rates during summer and winter peak hours will provide an incentive to customers to purchase more efficient heating and cooling systems. We also estimate the impact on load of introducing increasing block rates, in which the tailblock was set at the marginal cost that would result from the high environmental cost case. These estimates are summarized below:

Table 2: Summary of Results from Various Rate Designs for the Residential Class

Seasonal Rates	▪ Seasonal rates set at marginal costs (without environmental costs) could decrease residential peak season load, by 1% to 2%. ▪ Seasonal rates set at marginal costs reflecting our high estimate of environmental costs could decrease residential peak season load by 2% to 3%. ▪ Reductions in demand (MWs) may be somewhat less than the estimates of reduction in loads (MWhs).
Time-differentiated Seasonal Rates	▪ Time-differentiated seasonal rates could decrease residential peak period loads by about 8% and 9%. ▪ Time-differentiated seasonal rates reflecting our high estimate of carbon costs could decrease residential peak period loads by as much as 10%.
Tailblock Rates	▪ Tailblock rates set at marginal costs reflecting our high estimate of carbon costs.

These estimates must be accompanied by some important caveats. One is that these responses will not be instantaneous. While customers can take some actions quickly, it will take time for the purchase of more efficient appliances to have an impact and for customer behavior patterns to change significantly. In addition, price elasticities are the product of complicated analyses of customer behavior, and thus are not expected to be perfectly accurate.

To actually make such rate changes, utilities would work with their own actual data on load shapes and would also need to adjust rates so that they would collect the correct revenue requirement.

General Service and Total Results

The potential impact of rate redesign on general service (commercial and industrial, or C&I) customers is more questionable than the impact on residential customers. While larger customers have more load that can be shifted, the research also shows that price elasticities for industrial customers are fairly low and also quite variable. Some types of general service customers have very little ability to reduce or shift load while others have much more ability, particularly in the longer-run.

Research on commercial and industrial customers shows that time-differentiated rates appear to create some reduction in total load, as the decrease in load during the expensive periods does not all result in a corresponding increase in load during the less expensive periods.

It appears that seasonal rates could reduce C&I load but the impact is likely to be small. Rates that are both seasonal and time-differentiated rates could reduce peak period C&I load by 6% to 12%, because peak period rates, even that do not reflect high environmental costs, will be considerably higher than current average rates.

Overall, rate changes could possibly decrease loads and peak loads enough to postpone the need for new capacity in Kentucky for one or more years.

TASK 2: ALTERNATIVE RATEMAKING METHODOLOGIES

Task 2 A: Kentucky's Traditional Ratemaking Process

Description of Kentucky's Traditional Ratemaking Process

The ratemaking process in Kentucky exhibits three essential steps that are integral to ratemaking in jurisdictions across the country. These steps include:

1. **Revenue Requirements:** This initial step focuses on identifying the costs that each utility incurs in providing service, so as to determine the total revenues that must be recovered from ratepayers to ensure that those costs are covered and a fair profit is earned;
2. **Cost Allocation:** This second step encompasses allocating the costs that each utility incurs in providing service among the different customer classes, so as to establish the levels of costs (and thus the associated revenue requirements) that each customer class is causally responsible for; and
3. **Rate Design:** This third step focuses on calculating rates that (a) provide each utility with a reasonable opportunity to achieve its revenue requirements, and (b) implement various public policy objectives.

This Section addresses each of these steps, particularly as they relate to the challenge of establishing a rate structure that is likely to promote investments in demand-side services.

1. *Revenue Requirements*

The process by which revenue requirements are determined for Kentucky's utilities is well-established in the practices and precedents of the public utility commission. In order to remain a viable, ongoing concern in the delivery of essential services, each utility must receive sufficient revenues from its customers to cover its costs and provide investors with reasonable returns on invested capital. Determining the revenue requirement for each Kentucky utility involves the identification of costs for a historic "test year." These costs include fuel and variable operating and maintenance expense, and other expenses, including depreciation. They also include profits, which are calculated as a return on the utility's rate base. The revenue requirements portion of a rate proceeding typically includes consideration of the full range of operating expenses and capital costs. By applying standards of "prudence" and by requiring showings that various expenditures can withstand scrutiny under "least cost" expectations, the Commission examines both favorable and unfavorable changes at the same date, and determines what level of revenues is necessary for the utility to recover its costs and earn adequate profits based on a consistent view of costs.

Note that the revenue requirement includes a return, which provides compensation to stockholders and bondholders for the capital that they put at risk in financing operations. The Commission determines an appropriate allowed return on equity, and a total rate of return is calculated by combining the return on equity with return necessary to cover debt costs and income tax. Allowed earnings are determined by applying the rate of return to rate base, primarily investments in utility plant.

Although the rate case normally examines all costs and sets "base rates" until the next rate case, in Kentucky, utilities can essentially "true up" for their fuel costs after base rates are set, as noted below.

2. *Cost Allocation*

Once the increase in revenue requirement over existing revenues for a given utility has been established, the ratemaking turns to the task of designing rates to bring in the necessary level of revenues. The underlying concept here is that rates should be designed so that customers pay for the costs that they impose in the utility's system. It is necessary to determine how much to collect from each rate class. This is usually based on the class cost of service, but the specific class revenue targets will also be influenced by such other considerations of how much increase from existing rate levels is appropriate.

3. *Rate Design*

Once a utility's revenue requirements have been established and a class revenue targets are set, rates are developed to collect the class revenue target from expected sales. To take the simplest rate design, the revenue target would be divided by expected sales volumes.

Rate Riders

The Kentucky Public Service Commission has approved a number of special rate riders to supplement the base rates that are developed and implemented through the process described above. Such riders would result in rates "tracking" certain costs. These riders track fuel on a monthly basis, and also track Demand Side Management costs.

Ratemaking methodology and Utility Earnings

Once rates have been set through this process, the utility will earn the rate of return projected in the rate case **if** its expenses, net book value of plant, interest cost, number of customers, and sales remain the same as the projections used to develop the rates. Of course all of these components never stay the same. Some changes, such as fuel, do not create problems, because of the fuel adjustment rider. Changes in numbers of customers and in sales volumes create higher or lower revenue than projected.

TASK 2B: Assessment of the Benefits and Drawbacks of the Current Ratemaking Methods

Benefits of the Standard Methodology

In the standard methodology, rates are set after a thorough investigation of all costs, revenues, and sales. Usually the process begins with a review of actual booked values, but adjustments may be allowed for known changes to those values. The process aims for consistency in the time period for which costs and revenues are reported. Rate design is based on a consideration of all rate objectives, including determination of appropriate price signals. Customers know what there rates will be, except for such changes that flow through the various riders. The allowed rate of return is based on an assessment of the risks that the utility has historically experienced and observed changes in the electric industry. The utility can improve its profits until the next rate case through more efficient management of its costs, or if its sales increase faster than costs increase.

Drawbacks of the Standard Methodology Regarding Energy Efficiency

- Utilities have incentives to increase their rate base
- Utilities have no incentive to use demand-side resources
- Utilities have incentives to increase sales

Section 2C will focus on the three drawbacks of the standard methodology that may interfere with energy efficiency. From the standpoint of the utility, once rates have been set, its earnings depend on not only on its management, but also on sales volumes,[28] over which it has no control. If sales go down, revenues will decrease. Earnings may not fall, if costs decrease at the same rate as revenues, but a decrease in sales will mean that earnings will be less than they would have without the sales decrease. If sales increase, its revenues will increase. The utility has little or no control over a number of factors which cause its sales to decrease, such as economic conditions, weather, or customer-initiated energy efficiency. However, it does have control over its own Demand Side Management programs. If its programs decrease sales, its revenues will decrease, often with no offsetting decrease in costs. Even if such programs should decrease total long run costs, in the short run they can decrease utility earnings. It is often argued that traditional ratemaking does not provide efficiency incentives, since utilities can normally collect all of their incurred costs. However, once rates have been set, the utility can increase its earnings by reducing its costs.

[28] Earnings also depend on the number of customers, but for this discussion we will assume no change in the number of customers.

TASK 2C Alternative Ratemaking methodologies

All of the alternative methodologies begin with a regulatory review of the utility's costs. However, except for the Future Test Year methodology, the intent is that there will be some type of formulaic future adjustment to rates. These variants of ratemaking are advocated on the basis of being simpler (as opposed to changing rates only after full rate case proceedings) and providing better incentives to utilities for improving efficiency.

Future Test Year

This is basically a variant of the standard ratemaking approach, except that the utility projects costs and sales to a future year or years. If costs are based on expectations for the next year, it is appropriate that revenues and sales are based on a projection of the same year. If the utility has been experiencing or expects to experience sales decreases because of either customer-initiated energy efficiency or its own DSM programs, this decrease would be reflected in its projections. If the forecasts of future costs and sales were correct, the utility would earn the approved amount even though its sales decreased.

Performance Based Ratemaking

The basic concept of performance based ratemaking is that the utility is allowed to automatically adjust rates based on a formula that is supposed to reflect inflation and productivity increases. These formulae can be very complicated, but under the simple version the utility's earnings will decline from what they would have been if sales decrease.

Earnings Sharing Mechanism

This methodology also begins with a standard review of utility costs, but then allows or requires automatic rate adjustments if reported earnings increase or decrease beyond some approved limit. This would mean that if sales decreased enough to reduce the utility's earnings below the limit, it would be allowed an automatic increase. This method can also be very complicated. It was utilized for several years in Kentucky and was subsequently rejected.

Decoupling In Its Various Forms

Decoupling refers to a ratemaking methodology that "breaks the link" between utility earnings and sales volumes. The starting point for decoupling is still rates that are determined based on the standard ratemaking methodology, so that rates are set to collect an approved revenue requirement. The difference between this and the standard methodology is that it is not rates that are fixed until the next rate case, but rather the utility's fixed revenue.[29] There are a number of ways that this decoupling can be accomplished.

Version 1	Collect most revenue through fixed charges – utilities particularly advocate for this method for distribution revenues[30]
Version 2	Set revenue per customer (often for gas utilities) – if this declines, rates are adjusted upward until the same revenue is collected. If the number of customers increase, the total revenues can increase.
Version 3	Set weather normalized revenue per customer. Each year, estimate weather normalized revenues, and if the revenues decline, adjust rates upward until same revenue is collected. This approach could also reduce rates if revenue per customer increases because of increases in usage. Again, utility revenues can change with the number of customers.
Version 4	Set fixed revenue total; each year, adjust rates upward if this revenue has been under collected, downward if this revenue has been over-collected.
Version 5	Estimate what sales growth (per customer or in total, weather normalized or actual would have been in absence of decoupling - if this declines, adjust rates upward until same revenue is collected. In areas where load is growing, this is the approach that utilities are most likely to advocate –it attempts to put them in the same revenue position they would be if sales per customer continued its expected trajectory without additional energy efficiency.
Version 6	Combine decoupling and automatic changes in allowed revenues; estimate what future revenue per customer should be based on various adjustments to the revenue per customer calculation determined in the base rate case; these adjustments may reflect capital investment, and increases in expenses, so that even if use per customer does not decrease rates could increase.

The major experience in decoupling has been with natural gas local distribution companies. There has been a fairly strong trend of reduced use per customer of natural gas for a number of years, as major appliances using gas have become more efficient. The impact of improved efficiency from gas appliances has overwhelmed other influences on the use of gas. Most states now have tracking mechanisms that allow gas utilities to recover all of their supply costs, so this reduced use per customer is the reason why gas utilities need to file rate cases. As a result, a number of states have adopted gas decoupling mechanisms that provide utilities with automatic rate increases as weather normalized use per customer declines.

For both gas and electric utilities, decoupling is usually on a customer class basis, since use per customer varies greatly between classes. If decoupling were based on an average revenue that was not class specific, if a utility lost a big industrial customer, its average use per customer could decline significantly even though there would have been no energy efficiency involved.

There are many fewer states that have utilized decoupling for electric utilities. Several states utilized then rejected electric decoupling after a few years of experience with it. These include Maine, Oregon, Washington and New York. Decoupling was discontinued for various reasons,

[29] Excluding fuel and purchased power costs.
[30] High fixed charges mean low volumetric charges; the price per kWh no longer providing as much an incentive to conserve, so that the utility's disincentive has been removed, but customer's incentive has been reduced.. We will not consider this version of decoupling in the following analysis.

including significant rate increases, and restructuring of the electric industry in the state. In most areas, electric use per customer has been increasing. In these areas, DSM programs might reduce the rate of increase, but electric utilities may not actually experience reductions in usage as a result of DSM programs. States that do have electric decoupling mechanisms in place currently include: California, Idaho, New York, and Maryland.

Does Decoupling Address the Drawbacks That May Result From the Standard Ratemaking Methodology?

The primary focus of this section is whether an alternative ratemaking to the current ratemaking methodology, specifically Decoupling, can change the three incentives that may impact utility support for energy efficiency in Kentucky. This section also addresses other impacts on utilities and ratepayers that would or could result from adopting the decoupling alternative.

Incentives for utility to support sales growth

It is generally true that increases in sales per customer will increase earnings. This leads to the expectation that utilities under traditional ratemaking will be eager to increase sales, whereas Decoupling may eliminate the advantage of higher sales. Thus there is concern that utilities will encourage load growth, even when load growth may increase costs. How significant this is depends on whether utilities have much opportunity to increase sales per customer. If regulators do not allow advertising and do not allow rates that promote additional use, there may be little such opportunity.

Disincentive to utility DSM programs and Ratemaking methodology

Decoupling advocates have argued that under traditional regulation a utility's earnings are "entirely dependent on meeting or exceeding expected sales volumes"[31]. This is overstated; utility earnings will be dependent on a number of other factors, such as whether they can meet or beat expected cost projections. However, it is generally true that in the short-term sales reductions will reduce earnings and sales increases will increase earnings. This leads to the expectation that utilities under traditional ratemaking will not support energy efficiency measures that reduce sales. This same reasoning may not apply to programs that cause load shifting but not load reduction.[32]

While utilities may have a disincentive to support programs that reduce load, they will usually not have the same objections to load shifting.[33] If total load remains approximately the same, revenues may not decrease, but load shifting may actually decrease power costs[34] and increase reliability.

In the standard methodology, achieving expected revenues depends on actual sales equaling the projected sales levels which were the basis for the rates. If the projected sales account for the

[31] Bachrach & Carter, NRDC, p. 5-4.
[32] If rates are time-differentiated, shifting load to less expensive off-peak periods will reduce revenues, and may also reduce earnings.
[33] If rates are time-differentiated, shifting load to less expensive off-peak periods will reduce revenues, and may also reduce earnings.
[34] If fuel and purchased power costs are tracked and reconciled through a rate adder, utility profits will be neither worsened or improved by load shifting.

impact of DSM programs, then the utility's earnings would be as projected. This is one "fix" — an adjustment to sales volumes.[35] Of course, the utility would still be better off in terms of earnings if its programs did not produce the projected reductions in sales.

Kentucky has taken an alternative approach to this disincentive problem under traditional regulation. The utilities' approach to energy efficiency programs will be affected by the Lost Revenues component of the DSM rate riders. If the utilities institute a new energy efficiency program, they can estimate how much it will reduce sales and how much that sales reduction will reduce revenues. This revenue "shortfall" will be collected through the DSM rate rider.

The existing DSM riders should serve to remove the utilities' disincentive to instituting their own DSM programs. Thus in Kentucky the combination of traditional ratemaking plus the DSM rider means that with the current methodology utilities should not have a disincentive to support DSM programs. There may be some exception to this if the lost revenue component of DSM rider is incomplete. Generally the complaints regarding lost revenue computations is that they may favor utilities, providing more than the actual lost revenue, and they add complexity to ratemaking. However, utilities may still be negatively affected by energy efficiency that <u>does not result from</u> their own programs, because they receive no "lost revenues" adjustment for energy efficiency that is unrelated to their programs. Proponents of decoupling argue that with DSM riders utilities have an incentive to overstate the energy savings that result from their programs.[36] It is clear that using DSM riders requires effective regulatory oversight.

Do utilities have a positive incentive to encourage energy efficiency?

It has been posited that utilities may oppose DSM programs and energy efficiency in general because they may prefer adding rate base to reducing the total cost of electric supply through investing less and spending more on DSM. Thus even if they are do not lose revenues because of energy efficiency[37], utilities will usually find building generation more profitable than reducing demand. Energy efficiency does not automatically increase rate base the same way that building generation does. To the extent that this motivation is a problem, decoupling does not solve the problem. Explicit incentives for energy efficiency programs or penalties for failure to institute cost effective programs may be necessary. This would be true under the current methodology and also under the decoupling methodology. Decoupling should remove any disincentive that results from decreasing revenues, but does not create an incentive to encourage energy efficiency.

Incentives could take several forms, such as a return on investments in energy efficiency, or a higher reward return for meeting efficiency goals.[38] [39] These incentives can only be used if state laws regarding regulation allow them. Regulators may have the authority to order energy efficiency programs as contributing to the public good, and to penalize utilities if they do not comply. Offering either an incentive or a penalty associated with energy efficiency will require an additional regulatory task, that of monitoring energy efficiency performance. Once the

[35] This will only be a solution for the period of the sales projection – usually only the next year.
[36] If program savings are overstated, it would seem that more programs would pass screening tests.
[37] For instance, if a lost revenues provision in their tariff compensates them for lost sales due to their programs.
[38] EON's most recent DSM program requests that it receive an "incentive" revenue of 5% above program costs.
[39] For instance, Massachusetts includes in utility revenue requirements an 8% adder to DSM programs.

utility's energy efficiency strategy were determined, both incentives and penalties could assist in causing the utility to implement that strategy

> **Utilities' Perception of Energy Efficiency**
>
> All of this discussion has implicitly assumed that energy efficiency will simply decrease earnings and therefore be negatively perceived. This is not always and completely the case. If growth in load means that utilities must invest, which may mean an increase in rates and a decrease in credit rating, there may be strong public and possibly regulatory resistance to this path. In this case, the utility may face of disallowances or higher credit costs if it builds capacity than if the utility avoided the need for the additional capacity by encouraging energy efficiency.

We note that energy efficiency instituted by customers directly, unrelated to utility programs, may also reduce utility profits below what they would have been. Decoupling will remove this impact, even though the cause of the load reduction was not utility action. To the extent that the rate design changes that were discussed in Section 1D reduce revenues more than costs, utilities may argue against such rate changes. Decoupling would remove this reason for objecting to such rate changes.

Evidence Regarding Impact of Decoupling Methodology

Decoupling of gas revenues and sales has been around for awhile. Ten states have gas decoupling in place, and a number of others may be adopting decoupling. It appears that decrease in gas use per customer was a cause of decoupling. It is not clear how much decrease in use per customer was the result of utility DSM programs, or whether DSM programs were introduced or expanded in the decoupled states because of decoupling, since there are at least 29 other gas utilities that have energy efficiency programs. Electric utility decoupling has been adopted by Idaho, New York, and Maryland within the last six months, so there is no information on the results of this change in ratemaking methodology.

California has utilized a form of decoupling for a number of years. Their method is what was described as Version 6, which is called the Electricity Rate Adjustment Mechanism, or "ERAM". Utilities are essentially guaranteed not that they will collect the total revenues that were allowed in a rate case, but that they will collect a revenue per customer amount. The allowed revenue per customer is not fixed, but changes each year, reflecting complicated cost adjustment mechanisms. Advocates of decoupling point to California experience as evidence that decoupling contributes to energy efficiency. Use per customer in California has barely increased compared to use in the rest of the country over the last thirty years. However, California has a number of other unique characteristics that may explain why customer use has not grown compared to the rest of the country. First, California's rates have increased at a much higher rate over the last fifteen years, and those rates are very high compared to the rest of the country.[40] The theory of price elasticity tells us that this will have a dampening effect on

[40] California's average rates are approximately double Kentucky's average rates.

demand.[41] Second, state government has been strongly supportive of energy efficiency, and state efficiency standards and building codes will contribute to energy efficiency. Building codes can be very effective in a state with rapid growth, as new homes are required to be more efficient than old. Third, the public has been concerned with smog and other environmental issues, which should mean customer awareness of and support of the role that energy efficiency can play in mitigating environmental problems. Fourth, California utilities have supported energy efficiency programs for many years. This support may have been enhanced by decoupling, but we do not know by how much or what impact that support has had on energy efficiency.

Impacts of Decoupling Mechanism

The impact of decoupling on utilities is generally positive. Decoupling mechanisms reduce the variability of utilities' earnings. If the mechanism does not adjust for weather, but raises rates because of sales deviations caused by weather, this reduction in variability of earnings could be quite large. If the mechanism adjusts for any changes to weather normalized usage per customers, the utility will only get an increase in rates if sales actually decrease. If the mechanism adjusts for any change from projected weather normalized load, the utility would get an increase in rates when sales growth was less than projected. These various forms of reduction in revenue variability should result in some reduction of risk, which may be translated into lower required return on equity.

The impact on ratepayers is problematic. Decoupling shifts risks of sales reductions due not only to energy efficiency but to economic downturns from utilities to customers. This reduction in utility risk could be reflected in allowing a lower return on equity, but utilities have resisted this approach. Decoupling mechanisms will cause an increase in rates if sales decrease. Whether the increase is significant or not will depend on the magnitude of the change in sales. While these increases may be small, they may still create some confusion and disappointment in customers who adopted energy efficiency measures, as their reduction in usage will be partially offset by an increase in rates. There will also be some redistribution of revenue responsibility among customers within each rate class if all customers do not reduce usage equally. Since the mechanism provides the utility with the same fixed revenues as sales decrease, those customers who have not engaged in any energy efficiency will pay more as rates increase to maintain the level of revenues.

The impact of decoupling on regulatory agencies may also be a negative one. The initial establishment of a decoupling mechanism in itself requires additional regulatory oversight; for instance, if the mechanism is based on changes to forecast sales volumes, the sales forecast takes on considerable importance. The continuing utility requests for rate changes will require additional regulatory effort as well. The California ERAM adjustor requires very complex filings and oversight.

The impact of decoupling on utility support for energy efficiency appears to be positive. However, it is difficult to actually measure how important utility support is, and how important

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[41] The change in average use per customer may reflect the reduction in industrial customers (who tend to be the largest customers) in California.

decoupling is to utility support for DSM. Utility DSM programs that promote cost effective energy efficiency may result from the utilities' response to positive incentives or to the utilities; support of the concept of installing least cost resources. The American Council for Energy Efficient Economy, which ranks states energy efficiency efforts, ranked four states which do not have decoupling ahead of California.

TASK 2D: How DSM Programs can be Designed, Implemented, and Costs Recovered

This task examines potential means of implementing programs and recovering the cost of DSM programs and enhancing energy efficiency that are being utilized in Kentucky and elsewhere.

The Regulatory Underpinnings of an Energy Efficiency Strategy

Currently, utility filings regarding their Integrated Resource Planning ("IRP") efforts, requests for approval of new generating facilities through a Certificate of Public Convenience and Necessity ("CPCN"), and their DSM Programs appear to be separate efforts. The IRP review evidently does not at present entail a full case, investigation, and enforceable findings.

The Integrated Resource Plan should be central to resource planning, and should provide the basis for both DSM programs and requests to construct new generation. At the present time in Kentucky, the IRP process is an informal process. Although Staff issues a report on the utilities' filings, such a report does not carry the weight of a Commission order. Staff report findings are not directly enforceable as a result of the IRP process, but are rather recommendations on how to improve the next IRP. Although the IRP plans are "referenced" when utilities file CPCNs and DSM programs, the lack of direct connection and the lack of enforceability create the potential for significant gaps in effective planning. Environmental compliance plans must also be addressed at the same time, so that the cost of environmental compliance is taken into consideration in planning.

Without a consistent approach and strong regulatory oversight, a number of problems are possible. For instance, a CPCN filing may be based on different cost and load assumptions than had been used in the most recent prior IRP report. Without enforceability of the IRP plan, subsequent DSM programs may not achieve the cost effective level of energy efficiency, and generation additions may have to be larger in order than they would have been if the IRP plan had been enforceable. This could occur even if the utility's actions appeared to have been "consistent" with its IRP plan.

If the IRP, DSM, and Environmental Compliance plans, and any subsequent CPCNs were required to be consistent, all resources, both supply and demand-side, would be compared on a level playing field, with the same assumptions about resource costs, program savings and costs, and future loads. The approach would also be more comprehensive since resources would be considered on a portfolio basis.

Kentucky Utilities' DSM Programs

The Kentucky IOUs have developed DSM programs to offer to their customers, based on programs that pass certain tests as approved by the Public Service Commission. The utilities administer these programs directly. The Cooperatives appear to offer much less in substantive programs**.**

In July of 2007, KU and LG&E jointly filed their DSM application for expanding existing programs and adding more programs, mostly targeting residential and commercial customers. More DSM programs were found cost effective using cost/benefit tests this year, likely due to increased rates. Overall, all the proposed programs are expected to have cumulative reductions in load of 142 MW by 2010 and 303 MW by 2014.[42]

As noted in Section 1A, the Kentucky IOUs' Demand-Side Management Cost Recovery Mechanisms consists of a formula that allows the utilities to recover costs associated with demand-side management programs through formula based Demand-Side Management Cost Recovery Mechanisms which should track actual costs, an incentive, and also lost revenue. As noted earlier in this report, this will provide no recovery for revenue reductions which may result from other sources, including customer-initiated energy efficiency improvements.

One important issue to note is that under KRS 278.285, industrial (energy-intensive) customers who implement cost-effective energy efficiency measures themselves can opt out of being assigned a DSM cost. Because of this provision, there is a lack of utility DSM programs targeted at large industrial customers in Kentucky. Since industrial customers may not choose to implement all measures that could be cost-effective, this provision may reduce DSM potential in the state.

Non-Utility Administration of Energy Efficiency

One way of addressing potential utility disincentives to fostering energy efficiency, is to remove this responsibility from utilities. Several states have chosen to create energy efficiency programs delivered through non-utility administrators, instead of requiring utilities to administer energy efficiency programs. Sometimes the states have taken on the work for providing energy efficiency services and in other cases the state has contracted a consultant or group of consultants to implement the programs.

To fund non-utility programs, states charge all customers who are eligible for energy efficiency services a public or system benefits charge ("SBC")[43].

Pros

- State can offer programs that are consistent throughout the state with the potential for consolidated administration and marketing costs and initiatives.
- The consumer can better distinguish between the entity who is selling electricity to them and the entity promoting conservation.

[42] Case No. 2007-00319, filed July 19, 2007.

[43] In Vermont, the funding is collected by the utilities and provided to an agency that is independent of the state.

- Allows the state to refine or tailor the program without having to negotiate with the utilities.
- Administrators carrying out the work have a single focus on the program goals and are not distracted by other corporate goals of the utility.
- Performance incentives, shared savings and penalties can be built into the contract.
- Utility no longer needs to calculate or be compensated for its energy efficiency program costs and lost revenues.

Cons

- There is the risk that public benefits funds may be raided by the legislature for uses other than energy efficiency.[44]
- Some entity must be responsible for setting program targets and cost recovery.
- The utility but not the efficiency agency has the customers' usage history and an existing relationship.
- Utilities might still promote load-building efforts which can send consumers a mixed signal.
- A distinct funding stream can lead to a disconnect in resource planning between energy efficiency and other resources.
- Utility earnings may be negatively impacted by energy efficiency programs implemented by the agency, unless there is some recognition of revenue impact.

[44] This has happened in Wisconsin, Illinois, Ohio, Connecticut and Delaware.

RECOMMENDATIONS

Kentucky's history of very low electric costs has been changing - and it will change further as load growth necessitates building new capacity. It could change rather dramatically because of new environmental regulations. Kentucky's electric rate history explains why Kentucky electric customers use more electricity than in the U.S. as a whole, and why until recent there has not been a strong interest in improving energy efficiency. The changing cost situation and broader environmental concerns call for a number of responses. It will take time for all of the suggested response to have an impact on load. To avoid enough load five years in the future in order to delay building a power plant requires action soon.

Building codes and efficiency standards

We recommend that Kentucky should effectively utilize building codes and efficiency standards for new electric equipment, when cost justified, which may require enforcement of such codes and standards. Customers usually do not understand the long run results of the electric usage, and tend to make decisions on the basis of a short time horizon. Building codes and efficiency standards are means of increasing the efficiency of electric use that may not result from purely voluntary decisions.

Rate Design

We recommend that Kentucky consider various rate design changes that can contribute to energy efficiency. These include seasonal rates, possibly increasing block rates, and time-of-use rates that better communicate marginal costs. While this may not require large changes, this approach will introduce changes that may become even more important in the future.

Approach to DSM

At the present time, utility DSM programs may be missing a potential for a large amount of energy efficiency that could result from industrial programs. Programs appear not to have been developed for this class. The ability of industrial customers to avoid paying for any DSM by stating that they have instituted energy efficiency seems to be the reason that programs have not been developed for this class. Industrial customers generally will not have the knowledge, and may not have the inclination, to implement all cost effective DSM. Their decisions regarding energy efficiency will have been informed by their current electric rates and not by knowledge of marginal costs. Such decisions are unlikely to yield the same result that an analysis of the long-run impact of DSM will have on energy costs. Given the legislative provision regarding industrial customers' ability to opt out, we recommend that the Commission adopt a procedure to review whether the alternative measures are "cost-effective" on the same basis that is used to judge utility programs.

Decoupling

We recommend that decoupling should be adopted only after full consideration of all of the impacts of decoupling and if it is determined that the benefits outweigh the costs. This should include an investigation of how much incremental impact it will have on utilities' DSM programs, and in particular whether existing ratemaking methodology, including a lost revenues component to DSM and possibly a modified incentive to utilities, can achieve the same result. It should also include consideration of how it will impact utilities, ratepayers, and regulators.

Incentives for Efficiency programs

We recommend that Kentucky investigate what level of incentives and possibly penalties will be effective in encouraging implementation of cost effective DSM. Incentives for efficiency programs may be necessary, but they should be related to utility performance rather than simply the amount spent. Incentives that reward utilities for spending more encourage utilities to spend more, but unless there is very thorough oversight, the larger spending may not achieve the energy efficiency potential of the state.

Integrating Demand and Supply Planning

The Commission should provide firm direction to the utilities in IRP, DSM and Environmental Compliance proceedings, utilizing the same information that is or will be used in CPCNs. The Commission should review and make enforceable findings regarding the IRPs and DSM programs. Without this oversight and direction, supply planning and energy efficiency programs are less likely to achieve the Commission's major overriding goals. For instance, the PSC staff has recommended changes in screening of DSM which have and which will result in additional programs being included. The impact of such enhanced programs should be integrated into resource planning, as noted earlier. The IRP process can and should ensure that before plans to build expensive new generating facilities are approved, the utility has reflected the potential reductions in demand that will result from building codes, customer initiated energy efficiency, and DSM programs. This approach is being taken by many states where utilities are vertically integrated.

Introduction

Section 52 of HB 1, passed during the second extraordinary session of the Kentucky General Assembly, directs the Governor's Office of Energy Policy (GOEP), the University of Kentucky's Center for Applied Energy Research (CAER), the Kentucky Geological Survey (KGS), the Public Service Commission (PSC), and the Environmental and Public Protection Cabinet (EPPC) to produce a report and present recommendations to the Legislative Research Commission regarding carbon management research and technologies in coal-fired power plants. It is important to note that this report is a **snapshot**. This is a dynamic issue and this report is not the definitive answer on the state of legislation or technology. The issue is one that has dramatic implications for Kentucky and requires ongoing monitoring. For example, during preparation of the final draft of this document, the U.S. Senate Environment and Public Works Committee passed *America's Climate Security Act of 2007* out of committee, and the full Senate rejected a House Bill containing among other things stronger CAFÉ Standards as well as Renewable Electricity Standards, both of which were intended to address issues of global climate change, or greenhouse gas emissions.

This report focuses on carbon capture and storage issues related to coal-fired power plants. However, Kentucky has, through its incentives in HB 1, made a commitment to the development of gasification projects producing transportation fuels, synthetic natural gas, chemicals, and fertilizers from coal, coal waste, and biomass. These processes produce carbon dioxide ($CO_{2)}$ that can be more readily captured than that from existing power plants, but nonetheless produce significant amounts. This commitment to these projects increases the need to address carbon management options within the Commonwealth.

Before presenting the response to the questions outlined in HB 1, this report provides a general discussion of climate change legislation and activities outside of Kentucky, how this issue may impact Kentucky, and an overview of technological developments in carbon capture, utilization and storage. A more comprehensive treatment of the answers to the questions in HB1 is included in a full technical report in Appendix A. Other reports referenced in this document are included as appendices to this report. The reports included are but a small sample of the many reports available on this subject, and are not intended to be exhaustive.

Federal, Regional, and State Climate Change Actions

Several climate change bills are circulating in the Congress, with the one gaining the most attention, S.2191, also known as *America's Climate Security Act of 2007* (or the Lieberman-Warner Bill), expected to go to the full Senate in early 2008. This cap and trade bill places limits on emissions of greenhouse gases, with caps beginning in 2012 and becoming more stringent through 2050 (70% reduction from 2005 levels). The bill's target levels for emissions reductions are still being debated and additional amendments are likely. The momentum for action at the federal level, however, is escalating. As mentioned, this bill was passed out of committee on December 5, 2007.

A recently introduced bill addresses the need to rapidly commercialize carbon capture and storage (CCS) technologies. In early November, Sen. John Kerry introduced, S. 2323, which creates a competitive grants program for the construction of three to five commercial-scale sequestration facilities and the construction of three to five coal-fired demonstration facilities with carbon capture. It also establishes an inter-agency panel to develop a regulatory framework for CCS and calls for the U.S. Geological Survey to conduct an assessment of the sequestration capacity in the United States.

For a comparison of the greenhouse gas reduction targets and the assumptions and methodologies of all the climate change bills in the 110th Congress, visit the World Resources Institute (WRI) Web site: http://www.wri.org/usclimatetargets.

Also at the federal level, a recent Supreme Court decision, in Massachusetts v. Environmental Protection Agency, No. 05-1120 (April 2007), ruled that the EPA must take action under the Clean Air Act regarding greenhouse gas (GHG) emissions from motor vehicles, has significant implications for electric generating units and all other stationary sources. The E.P.A. is currently writing rules to comply and is weighing an application by California and 14 other states to set their own emissions standards.

As the United States Congress debates greenhouse gas legislation, many states such as California and Florida are acting on their own or in collaboration with other states in their regions. Some states have imposed limits on GHG, while many have joined carbon dioxide registries, or have formed workgroups to assess potential actions. Twenty states have committed themselves in some way to a regional cap-and-trade program. The Lieberman-Warner bill includes incentives for states to adopt climate policies that are more stringent than the federal program.

At the regional level, there are several cap and trade initiatives: the Regional Greenhouse Gas Initiative among states in the northeast; the Western Regional Climate Action Initiative among 5 western states; and the Midwestern Greenhouse Gas Reduction Accord. There is also a recent initiative among states to establish a uniform greenhouse gas emissions reporting system, which all but 11 states have joined.

Kentucky's Electric Landscape

Kentucky relies on coal-fired power for more than 90 percent of its electricity, and in 2006, this resulted in more than more than 93 million metric tons of carbon dioxide emissions. When discussing legislation mandating reduction of these emissions, it is important to consider that the existing fleet cannot be replaced quickly; substantial modification will also take time and impose costs. With the increasing possibility of carbon constraints in federal legislation and regulation, Kentucky must find ways to utilize its existing resources – fossil fuels, renewables, and energy efficiency -- and develop and deploy new technologies to positively respond to the challenges with the goals of maintaining the Commonwealth's low-cost energy and preserving the Commonwealth's commitment to environmental quality.

In 2005, the Public Service Commission's projected that Kentucky will need an additional 7,000 MW of generating capacity between now and 2025 (*Kentucky's Electric Infrastructure: Present and Future, An Assessment Conducted Pursuant to Executive Order 2005-121*). This growth will be the result of population growth, economic growth in the Commonwealth, and increased electricity use per household. It is important to note that this does not include the retirement of any existing power plants, some of which are operating beyond their expected life.

Regulated utilities serving customers in Kentucky will have to meet the needs of these customers, as is the nature of the regulatory compact, which allows them to serve as a regulated monopoly within the boundaries of their service territory. This "obligation to serve" will mean that the power needs of their customers must be met through market purchases or by the building of new generation.

Historically, Kentucky's citizens have been fortunate to have had some of the lowest electricity rates in the nation. These low rates have not only benefited residents, but they have helped to attract major energy intensive industries that provide high numbers of well-paying jobs throughout the state (aluminum smelters in Western Kentucky, automotive manufacturers in Central Kentucky, steel mills along the Ohio River). Federal legislation, whether it be in the form of a carbon tax or cap and trade program, will make coal fired electricity generation more expensive. Utilities would have to pay the carbon tax or in the case of cap and trade, either make investments to reduce carbon emissions or buy carbon credits. These costs will be passed on to the ratepayer. The economic impact of a carbon-controlled future on the state of Kentucky could be significant. Estimates are that the cost of adding carbon capture and sequestration capability at existing coal-fired facilities will increase electricity costs of between 50% and 300%.

Any legislation that adds costs to coal-fired electricity generation that are not also levied against other forms of generation would raise Kentucky's rates disproportionately compared with states having other resources and would thus lessen the differential in cost of electricity that Kentucky currently enjoys with respect to other states.

One way to reduce the impact of any rate increase would be to increase end-use efficiency in the Commonwealth. This would also help achieve carbon reduction goals. Kentucky has one of the highest per capita electricity consumption rates in the nation. While some of this per capita use of electricity is due to the energy intensive industries located in the state, per capita residential use is also high relative to the rest of the country. A recent report completed for the Governor's Office of Energy Policy states, "Kentucky's electric rate history explains why Kentucky electric customers use more electricity than in the U.S. as a whole, and why until recently there has not been a strong interest in improving energy efficiency. The changing cost situation and broader environmental concerns call for a number of responses." (La Capra and Associates, *Report on Rate Design and Ratemaking Alternatives as They Impact Energy Efficiency*, November 2007, see Appendix H). The La Capra report recommends a broad range of actions to spur end use energy efficiency in all economic sectors. HB1 has directed the

Public Service Commission to examine existing statutes as they relate to energy efficiency and to make recommendations to the General Assembly.

Another method to decrease the carbon dioxide emissions associated with generation of electricity is to increase the percentage of generation capacity that uses renewable resources. Kentucky has limited potential, *given today's technology*, to use renewable resources to meet base-load power needs. According to the U.S. Energy Information Administration (EIA), in 2005 (the most recent data available), renewables (mostly hydroelectric) generated 840 MW, or approximately 4.3% of Kentucky's electricity. There is some potential for growth in the areas of hydroelectric and landfill methane gas, and HB1 provides some incentives for the development of renewable technologies. Kentucky, was one of the first states that signed the 25 x '25 initiative, with a goal to use renewable energy and energy efficiency as a means to get at least 25 percent of our energy from improved technology and renewable resources, such as solar, biomass and biofuels, by the year 2025.

The increased use of energy efficiency and renewable assets will not eliminate the need for base-load generation. What fuel to use for that base-load generation is in some states being answered by a growing interest in nuclear generation; in Kentucky, that is not an option, as it is at this time statutorily prohibited.

In other states, proposed coal fired power plant projects have been abandoned or changed to use natural gas as a fuel source, in order to reduce their carbon intensity. A natural gas combined cycle plant generates approximately half the carbon dioxide per kilowatt hour. Kentucky has a number of natural gas-fired turbines that are used for peak generation of electricity. To use more natural gas in electricity generation would require construction of large base-load units to replace the current fleet of coal-fired generators. The costs of the new construction and the cost of base-load generation would be prohibitive. In addition to the capital costs, the fuel costs of natural gas are higher and more volatile than coal. The United States is becoming increasingly dependent upon imported natural gas, and this would exacerbate the energy security issues associated with importing energy resources. This increasing demand for natural gas for electricity generation will lead to higher prices for home heating and for industrial markets. For these reasons, natural gas is not expected to meet much of the future needs of base-load generation.

Because of its low cost and abundance, coal will continue to provide much of the Commonwealth's base-load electricity. According to many government, academic, and industry figures (among these, the Massachusetts Institute of Technology, World Resources Institute, Electric Power Research Institute, Energy Information Administration, Congressional Office of Management and Budget) coal will also continue to supply the country with base-load generation for many years.

Technology Solutions

Even taking into account anticipated future greenhouse gas emissions limits; expectations are that the country will continue to use coal as a fuel for electricity generation. In the past, the utility industry has met its growing need for electric generation and has dramatically reduced total emissions of sulfur dioxide, nitrous oxides, and mercury while increasing the amount of electricity generated from coal fired power plants. In the same way, efficiency improvements and technology developments can enable the industry to continue to utilize coal while reducing emissions of carbon dioxide. The improvements and technology development are already underway. For these to be successful in meeting demands for substantial carbon dioxide emissions reductions, public policymakers must commit a level of financial support for research and development sufficient to scale up the size of the demonstration projects currently under development and to do so in a much shorter time frame than is now planned, and with an eye toward the deadlines in the relevant federal bills under consideration.

There are five major technological paths to carbon dioxide reduction in coal fired power plants: (a) co-firing existing power plants with biomass and coal; (b) improving the efficiency of existing power plants; (c) installing new and more efficient generation technologies; (d) installing carbon separation and capture technologies; and (e) sequestering the captured carbon dioxide. Co-firing wastes or biomass can have significant and immediate CO_2 reduction impact due to replacing a substantial portion of coal (up to 15 percent by weight appears technically feasible if resources are available) with carbon neutral biomass. Improving efficiency at existing plants by operational or maintenance modification can yield reductions in CO_2, of 10%-16% in a unit, and overall fleet improvement of 3%-5% (CURC). New, more efficient technologies include units that produce steam at extremely high temperatures and pressures (ultra-supercritical pulverized coal, or USCPC) and integrated gasification of coal and combined cycle generation (IGCC).

Currently, new supercritical and ultra-supercritical power plants are producing approximately 10%-18% less carbon dioxide emissions than a conventional pulverized coal (PC) power plant. CURC/EPRI estimate that by 2025, the greater efficiencies of supercritical and ultra-supercritical power plants could result in 35 percent fewer emissions than those from the same size conventional power plant. Installing supercritical and ultra-supercritical boilers on existing plants would be very costly; however, the cost of a new super- or ultra-supercritical plant is not much greater than the cost of a conventional plant, and with continual improvements, the cost differential will be reduced (CURC/EPRI).

IGCC plants combine considerably greater efficiency with much improved control of CO_2 and also sulfur dioxide, nitrous oxides, and mercury. Because of higher construction and operating costs, the cost of electricity from an IGCC plant may be as much as 35 percent higher than from a conventional PC power plant. However, as multiple IGCC plants are deployed, operated, and improved, this differential is expected to decrease greatly.

There are technologies in development that can be used on existing power plants or built into the design of new power plants that remove CO_2 from flue gases (post-combustion). These technologies are being modeled on currently utilized industrial processes for producing pure carbon dioxide for commercial and industrial applications. These offer high CO_2 removal in the near to mid term, but they presently impose high costs for installation and can require up to one-third of the electricity generated by the power plant just for operating the chemical removal equipment. There are technologies in development that show promise at reduced cost, but they have not been demonstrated at large scale. Other technologies such as the new techniques of firing coal in oxygen rather than air (oxy-combustion) can produce near pure streams of CO_2 for capture and utilization or sequestration. These processes also currently are very costly in both equipment costs and parasitic drains on the electricity generated by the power plant largely for operation of air separation units needed for production of oxygen. IGCC offers efficient capture of CO_2 and at operating costs that are quite manageable, once the capital cost of the power plant is met.

Carbon reduction, separation and capture are only part of the equation. If carbon dioxide is produced and is not to be released into the atmosphere, it must be stored. Enhanced oil recovery (EOR), enhanced coal bed methane recovery (ECBM), and enhanced gas recovery (EGR) all will play a part in the storage of captured CO_2. For example, in the Weyburn Oil Fields in Canada, CO_2 is carried in a pipeline captured from the North Dakota Gasification Plant and is used to increase the production of the field. It is predicted that the CO_2 EOR operation will enable an additional 130 million barrels of oil to be produced, extending the field's commercial life by approximately 25 years. It is anticipated that about 20 million tons of CO_2 will be injected and become permanently stored 1,400 m (4,600 ft) underground over the 25 year lifetime of this project. Increases in this use of carbon dioxide will depend largely on the development of large-scale pipeline systems for delivering CO_2 to the points of need.

EOR, ECBM, and EGR have potential in Kentucky; however, it is unclear how much storage capacity is available. This is an area that HB1 provided funding for further research. There are some other uses for $CO_{2,}$ such as those in the food, drug, and chemical industries. It is unlikely that these uses will utilize the volume of CO_2 needed to be captured. For example, the amount of CO_2 produced by electricity production in the United States in 2006 was over 2.4 billion metric tons, according to the Energy Information Administration (EIA). (Compare this to the 20 million tons to be stored in the Canadian EOR project over the 25 year lifespan of the project.)

It is important to determine what the capacities for these beneficial uses for CO_2 are in Kentucky, so that the cost of removal, transport and injection can be offset by revenue. However, because of the volume needed to be stored, permanent storage or sequestration in geologic formations is the only viable option at this point for removing large volumes of CO_2 from the atmosphere.

The KGS has found that the subsurface geology of Kentucky is generally favorable for carbon sequestration and enhanced oil and gas recovery. The U.S. DOE *Carbon Sequestration Atlas of the United States and Canada* estimated in 2007 that over 3,500 billion tons of CO_2 sequestration potential exists in the United States and Canada. The U.S. DOE has begun a three-phase research program that includes assessment and validation of potential and large-scale demonstration of sequestration. The KGS is participating in three of the regional sequestration partnerships. Numerous legal issues relating to CO_2 ownership and liabilities are being addressed by several government and academic entities. The MIT study, *The Future of Coal*, concluded that "there do not appear to be unresolvable open technical issues underlying these questions…" and that "the hurdles to answering these technical questions well appear manageable and surmountable."

The Battelle Global Energy Technology Strategy Program in 2006 reported that "assuming that other advanced technologies are developed and deployed along with carbon capture and storage systems, this potential storage capacity should be more than enough to address CO_2 storage for at least this century."

The geology of Kentucky seems suited for long term storage or sequestration, but deep wells have not been drilled and original data has not been gathered at depths to know definitively. The Kentucky Geological Survey along with private partners is interested in forming a public/private partnership, along with the Commonwealth, which allocated $5 million in HB1, to collect original data to better assess the capacity of the geology for sequestration.

Recommendations

The pace of the research and development may not be sufficient to meet the challenges especially to the electricity sector in Kentucky. As a result of the research conducted to respond to the thirteen questions outlined in HB1, we respectfully offer the following options recommendations to the General Assembly to consider when looking at this important issue going forward:

- Provide incentives or grants for large scale public/private partnerships between the Commonwealth, utilities, Kentucky's research institutions, and carbon capture technology providers to site large scale carbon capture technology research and demonstration projects in the Commonwealth.

- Encourage through additional funding, the further development of large scale carbon dioxide storage demonstration projects, including EOR, EGR, ECBM, storage in deep unmineable coal seams, and geological sequestration.

- Develop mechanisms whereby the Commonwealth can provide some liability protection for the demonstration projects for carbon capture and storage, to encourage participation of private entities in public/private partnerships.

- Provide funds for public education/outreach programs to educate the public on carbon sequestration.

- Provide the Public Service Commission with tools necessary to encourage utilities to develop and adopt new technologies that can reduce or capture carbon dioxide. This could include incentives and/or cost recovery for the early adoption of new generation technologies, cost recovery for renewable energy development, and cost recovery mechanisms for research and development programs.

- Provide the Public Service Commission with tools necessary to encourage utilities to develop and adopt new policies that can support reduction or capture of carbon dioxide. This could include changes in rate design or changes in demand side management programs in order to promote increased energy efficiency.

- Determine appropriate incentives or necessary statutory changes to encourage adoption of energy efficient products and practices by consumers and to implement the recommendations of the November 2007, *Report on Rate Design and Ratemaking Alternatives as They Impact Energy Efficiency*.

- Alter economic development tools presently in existence to specifically help energy-intensive industries make adjustments to remain viable in a higher rate environment.

- Establish an informal Carbon Dioxide Working Group consisting of energy leaders in the legislature, the executive branch, research universities, industry, and environmental groups in order to keep abreast of the ever changing legislative environment and technology development.

- Encourage the federal delegation to increase funding in research and development of carbon capture technologies and carbon sequestration.

- Encourage the federal delegation to work to ensure that if regulations on carbon are put in place that they be no more stringent than those for natural gas combined cycle power plants. This decrease in the required percentage removal from a coal facility could result in a decreased cost of removal of carbon dioxide from these facilities, as the cost of many of the processes increase exponentially as a higher percentage of carbon is removed. This would ensure a more level playing field.

- Work with the federal delegation to attempt to influence the federal legislation in such a way as to dampen the rate shock to Kentucky ratepayers.

Summary of Responses to Questions

1. The current status of research and technology to manage carbon dioxide in existing coal-fired power plants.

Many technologies for managing carbon in existing power plants are being developed and improved continually. However, except for the most inexpensive techniques for increasing plant efficiency through operational and maintenance improvements, the technologies are costly to install and operate and often greatly decrease the marketable electricity output of a generating unit. Nonetheless, progress is being made, and plans are being advanced for substantially reducing carbon dioxide emissions at relatively low cost and with manageable electricity penalty within two decades. CURC, MIT and others argue that all technologies should be developed, including fuel switching, modification of existing plants, and development of advanced technologies for new plant. This will require a very strong and continuing federal commitment. Currently, federal funding for research and demonstration of technologies for capturing carbon dioxide is grossly inadequate.

There are three basic methods available to manage carbon dioxide in existing coal-fired power plants: (1) Replace some percentage of coal with a more carbon neutral fuel to reduce a plant's "carbon footprint;" (2) Increase power plant efficiency; and (3) Capture the released carbon dioxide.

Switching some percentage of the gross heat input to the boiler from coal to biomass effectively reduces the amount of net carbon dioxide emitted to the atmosphere. This results in a net decrease of carbon dioxide emissions per measure of electricity produced. Biomass blending is a relatively inexpensive (material handling/processing equipment; possible burner changing/tuning), easy (simple, proven technology), and quick way to help meet potential carbon reduction goals. There is considerable experience world-wide with biomass blending of many types at a variety of facilities, with mixed but generally good results. There is uncertainty, though, as to how compatible a particular boiler will be with a particular fuel. A more significant potential risk is that according to current EPA rules, fuel switching may trigger New Source Review (NSR) requirements which could require that Best Available Control Technology (BACT) be installed on the basic power plant. That could raise costs at a particular facility considerably. Biomass co-firing coupled with capture and storage of carbon dioxide could dramatically reduce a coal-fired power plant's carbon footprint.

The second method is to increase the thermal efficiency of the power plant. The efficiency of PC boilers has been increased greatly through construction technologies that allow the boilers to produce steam at very high (supercritical) or ultra-high (ultra supercritical) temperatures and pressures. A new supercritical unit compared to a relatively new subcritical unit would see a 10 percent decrease in the amount of CO_2 emitted for the same power production. There is potential for ultra supercritical and IGCC units to have even better efficiencies. Assuming an existing plant efficiency of

35%, a 1% efficiency improvement at a 500 MW unit could result in 4.5 million fewer tons of carbon dioxide emitted over a 40 year plant lifetime.

Some increase in most (especially older) plants' efficiency would be relatively easy, cheap, and quick, though both cost and effectiveness will vary widely from facility to facility. The more complex options for increasing efficiency such as upgrading the operating temperature and pressure of the boiler and/or adding a gas turbine to the power plant would entail much greater costs and take much longer, though they would result in substantial efficiency gains. Having additional power available for sale without the necessity of building new plants is a big plus. Incentives involving rate setting and cost recovery are also cash non-intensive. Possible federal (EPA) regulatory impediments MUST be removed to gain maximum effect. Assuming that an average of a 5% thermal efficiency increase is achieved throughout the fleet, it would mean that the same number of MWh of electricity will be generated with a 10% reduction in CO_2 emissions.

The third method, capturing released carbon dioxide from the combustion gases, requires processes such as chemical solvents, physical absorption, membrane systems, or other methods that are in different stages of development or testing. Of these, **chemical solvent methods** are the only ones approaching power plant scale demonstration and deployment. The primary impediment to capturing carbon dioxide in existing coal-fired power plants is the huge volume of combustion gases, containing (typically) 12-15% CO_2 by volume, that are generated when coal is combusted in air. It is difficult and costly to separate and capture the dilute carbon dioxide from the rest of the combustion gases.

Analysis conducted at the National Energy Technology Laboratory (NETL) predicts that CO_2 capture and compression using amines [e.g., monoethanol amine (MEA) extraction] will raise the cost of electricity from a newly-built supercritical PC power plant by 84%. Costs at an existing supercritical or sub-critical plant will be higher due to the difficulty of adding equipment to units not designed from the start for such technologies. In addition to the costs of capital equipment and the solvent itself, the MEA process is expected to demand about 20%-30% of the generated gross power output to operate the system.

Another approach to capturing CO_2 involves removing the oxygen from air and then burning the fuel in that oxygen mixed with recycled flue gas or water (which is then condensed from the exhaust stream) to produce a much more highly concentrated stream of CO_2. This process, called oxy-fuel combustion, results in a concentration of 80+% CO_2 in the exhaust, with a much lower volume of flue gases (approximately 70% less). This greatly reduces the cost and difficulty of capturing the CO_2 released from the boiler. The biggest costs of oxy-fuel combustion are the stand-alone air separation unit (ASU) required to produce the oxygen and further flue gas purification to bring CO_2 content to the same level (90+%) obtained from post-combustion CO_2 capture processes. In addition to the cost of the ASU itself, approximately 20% -30% of the gross power generated by the power plant is consumed by the ASU to produce the oxygen.

2. Existing sources of support for research related to managing carbon dioxide in existing coal-fired power plant and the adequacy of such sources

There are countless groups in the United States and around the world that are involved in research on carbon capture and sequestration, both from existing and new power plants. These sources can be divided into four basic groups: Government, academic, private research groups, and private industry.

In the United States, the best known government organization is the U.S. Department of Energy (DOE). Through the National Energy Technology Laboratory (NETL), DOE provides funds and is a partner to various other entities engaged in research, development, and deployment of carbon capture and storage projects. In 2003, the DOE formed seven Regional Carbon Sequestration Partnerships (RCSPs) to look at the implementation of carbon sequestration in the United States on a broad scale and lead a national effort to develop the infrastructure and knowledge base needed to commercialize carbon sequestration technologies.

Individual states also have government organizations which actively support research in carbon management, such as the Ohio Coal Development Office, the Kentucky Geological Survey (KGS), and the Kentucky Governor's Office of Energy Policy. KGS is currently doing carbon sequestration research that is primarily focused on geologic storage options in Kentucky. Their work applies to managing carbon at both existing coal-fired power plants and future coal gasification projects. KGS is currently funded for work in three of DOE/NETL's regional carbon sequestration partnerships: (1) Midwest Regional Carbon Sequestration Partnership (eastern and central Kentucky); (2) Midwest Geologic Sequestration Consortium (western Kentucky); and (3) Southeast Regional Carbon Sequestration Partnership (eastern Kentucky coals). In addition, KGS receives funding from the Kentucky Governor's Office of Energy Policy for regional sequestration and CO_2 enhanced oil recovery evaluation. The DOE regional carbon sequestration partnership work in Kentucky has primarily involved evaluation and mapping of existing data. Only one demonstration project involving the drilling of a well and new data collection is planned in Kentucky (in Boone County).

House Bill 1 passed during the 2007 special session will provide KGS funding to obtain much needed geologic data in both the eastern and western Kentucky coal fields, where future coal gasification projects are likely to be built. These parts of Kentucky have not been chosen for demonstration projects in the DOE sequestration partnerships, and through the HB1 funding, Kentucky will be able to better evaluate the location and size of geologic sequestration targets.

The second group spearheading and facilitating research in carbon management is academia. Many universities that have an emphasis on scientific and/or engineering curricula also have energy research centers and/or conduct research on carbon management projects. Purdue University's Energy Center, MIT's Laboratory for Energy and the Environment, and the University of Kentucky's Center for Applied Energy

Research are typical examples. Additionally, many universities such as the University of Texas at Austin are engaged in research projects on specific aspects of carbon capture and control.

Companies that are involved in one or more aspects of power generation are also working to reduce the carbon footprint of coal-fired power generation. American Electric Power (AEP), Duke Energy, E.ON, Foster Wheeler, Babcock and Wilcox, Alstom, Air Liquide, Praxair, Mitsubishi Heavy Industries, and Air Products are just some of the multitude of private companies working in this area.

According to many industry sources, the current research budget for DOE is not sufficient to provide the funding to achieve carbon management needs. If technology is to be the centerpiece for addressing concerns about climate change, then adequate funding and focus is urgently required and sufficient time to develop innovative CO_2 capture technologies is needed. For example, CURC estimates that a long-term research, development, and deployment effort to reduce CO_2 emissions significantly through carbon capture and sequestration would run through 2025 and cost $18 billion.

Several private consortia and private advocacy groups are facilitating or conducting CCS research. Among these are the Electric Power Research Institute (EPRI), the Southern Research Institute (SRI), RTI International, the Western Research Institute (WRI), and the Coal Utilization Research Council (CURC). These groups work with industry and academia to identify and fund promising research projects for carbon capture and removal.

In establishing a research alliance called the "Kentucky Consortium for Advanced Power Generation," CAER pledged $1 million annually in state funds (it is envisioned that these moneys will be supplied as part of a recurring funding line for CAER as described in HB 1) to match funding the CAER will receive from the utilities and other private sector partners. However, a capital investment of $4 million will be required, along with the funding provided by the various utilities in the consortium, to cover the capital cost of the project.

3. The estimated capital and energy costs associated with installing the technology or upgrading existing coal-fired power plants to better manage carbon

As stated, achieving the goal of better carbon management at existing PC power plants can be done in three ways. Arguably the lowest cost technique would be to fire a certain percentage of renewable (near carbon neutral) biomass with coal to reduce a plant's net carbon emissions. There are some costs involved with upgrading existing equipment, such as storage, pulverizers and fuel mixing, but these would be relatively small compared to other options.

The second method is to increase the thermal efficiency of the power plant. Newer units generally have greater thermal efficiency and reduced CO_2 emissions per MWh of electricity produced. This is shown by the lower ratio of BTUs per MW. A new supercritical unit compared to a relatively new subcritical unit would see a 10% decrease in the amount of CO_2 emitted for the same power production. There is potential for ultra supercritical and IGCC units to have even better efficiencies.

Thermal efficiency can be increased at existing coal-fired power plants by retrofitting the sub-critical plants to supercritical or ultra-supercritical performance, or by making a combined cycle plant by adding a gas turbine to the basic steam turbine. Both of these methods would increase the thermal efficiency from approximately 35% to 45-50%, resulting in a decrease in carbon emissions of 20-30%. Unfortunately, converting a sub-critical plant to supercritical or ultra-supercritical performance would require essentially a complete rebuild of the plant, which is economically unfeasible. Adding the complete gas turbine package to an existing plant would cost hundreds of millions of dollars, but would have the advantage of actually increasing net power output instead of decreasing it because of parasitic load.

The third method is to capture and control carbon emissions from the flue gases. For new fossil power plants, the DOE/NETL issued a technical report, *Cost and Performance Baseline for Fossil Energy Plants*.

According to this DOE report for new power plants using bituminous coal, the impact of the addition of commercial 90% carbon capture technology is as follows:

Generation Technology	Increase in Capital Cost based on $/kW	Energy Efficiency Loss, based on HHV
NGCC	112%	14%
PC (subcritical)	87%	32%
PC (supercritical)	82%	30%
IGCC	36%	19%

The **impact on existing units** would be higher due to the nature of adding equipment to units not designed from the start for such technologies. All but two of the PC power plants currently in Kentucky are sub-critical; there are two existing supercritical units and a third in construction. At this time, the costs of retrofitting existing sources with carbon capture technologies are highly speculative. Estimates are that the cost of adding carbon capture and sequestration capability at existing coal-fired facilities will increase electricity costs of between 50% and 300%.

Estimates from studies done by the MIT, NETL, and others show the cost of capture and compression, not including disposal, of CO_2 at existing sub-critical/supercritical PC boilers would increase electricity costs somewhere between 69% and 100%. The variations in these predicted increases are because capital costs for the equipment to capture and compress 90% of the carbon dioxide emissions from an existing power plant will vary radically between facilities due to site specific layout and technological considerations. An additional cost is the energy required to capture and compress the CO2; this cost is estimated to be around 30% of the net output of a typical PC boiler. The final (and again highly variable) cost component of carbon management is the disposal of the carbon dioxide. This will depend on whether or not there is a commercial use available, the distance between the existing plant and the storage/use site, and the (at this time unknown) cost of required infrastructure to move the carbon dioxide from the plant to its final destination.

Efforts are being made to reduce the uncertainty of carbon dioxide transport and storage costs. Compared to storage costs, transport costs are much more easily determined. CO_2 pipelines have been built in many parts of the country, and the technology is established and readily available. CO_2 pipelines operate at higher pressures than natural gas pipelines (2,500-2,700 psi), but are similar to liquefied petroleum gas (LPG) pipelines. Pipeline construction costs will vary with diameter (flow rate) and distance.

4. Identification of specific potential research projects and demonstration projects to enhance the development and deployment of new technology in this area

CAER is requesting funding to expand applied research projects that focus on three approaches for reducing carbon dioxide and other emissions from fossil-fuel power plants:

- Concentration and capture of CO_2 released by coal-fired power plants. The funds requested will be used to (a) modify an existing CAER pilot-plant combustion facility into a versatile CO_2 capture research platform, (b) construct and incorporate a scaled-up, slip-stream version of the platform into the flue gas stream at a selected PC power plant. This objective represents a critical step in developing and demonstrating practical technologies for reducing CO_2 emissions from Kentucky's existing fleet of coal-fired power plants; (c) expand the capability of the ongoing algae bio-fixation study;
- Increase power plant efficiency. This effort will not only increase the amount of electricity produced from each ton of fuel but would do so while simultaneously reducing the amount of emissions per unit of power generated;
- Reduce the overall carbon footprint of the power plant by increasing the use of renewable biomass and agricultural waste resources via production of liquid, gaseous, and solid fuels.

The KGS received $5 million in funding from HB1 (2007 special legislative session) to drill research wells to characterize CO_2 EOR, EGR, and deep permanent sequestration. Over the next 3 years, these KGS projects will provide much needed hard data to characterize the available sequestration options in Kentucky.

One new KGS research project is named "Evaluation of Geologic CO_2 Sequestration Potential and CO_2 Enhanced Oil Recovery in Kentucky." This study is funded by the Kentucky Governor's Office of Energy Policy. The goals of this project are (1) to evaluate the potential for using CO_2 in EOR in major oil fields in Kentucky, and (2) to conduct a regional evaluation of geologic sequestration potential within the Commonwealth. This research will provide a better idea of the quantity of CO_2 that could be utilized in EOR, and the areas and specific targets where geologic sequestration is possible.

Over the last 4 years, KGS has participated in research efforts in the three U.S. DOE carbon sequestration regional partnerships that include Kentucky. These are the Midwest Geologic Sequestration Partnership (MGSC), the Midwest Regional Carbon Sequestration Partnership (MRCSP), and the Southeast Regional Carbon Sequestration Partnership (SECARB).

5. Identification of the types of incentives or other government assistance that would be helpful in supporting the development and implementation of new technologies to reduce carbon emissions at existing coal-fired power plants, including strategies for isolation, capture, and management of carbon dioxide.

A program of taxes or incentives (or a combination of both) to maximize electricity production with minimum CO_2 emissions would encourage carbon footprint reduction.

In the 2007 special session, the Kentucky legislature passed House Bill 1, which included funding for sequestration research at the Kentucky Geological Survey. While this funding is essential to help establish Kentucky's CO_2 sequestration potential, the bill did not provide incentives that will facilitate commercial implementation of carbon capture and storage (CCS) technology. Such incentives will likely be needed for successful development of this technology.

There are currently thirteen facilities in Kentucky that generated 91 million tons of CO_2 in 2006. Sequestering that amount of material will be a complex and expensive task. Unresolved liability risks related to the transportation, injection and storage of enormous quantities of CO_2 in geologic formations is a significant barrier to mobilizing the necessary capital for the needed R&D. Any protection that minimizes or spreads the risk from such litigation would reduce the potential cost and increase the likelihood that projects of this type would be attempted in Kentucky.

Several states have been active in drafting and enacting legislation to provide incentives for clean coal technology development. Most of these initiatives deal with cost recovery, financial assistance, tax credits, and regulatory changes pertaining to coal gasification and coal-to-liquid development. Few of these initiatives deal directly with carbon management or sequestration issues

Two good examples of the types of incentives that will be required to enable large-scale CCS technology can be found in recently passed bills in Illinois and Texas, both of which are pursuing the federally funded FutureGen zero-emission coal generation project. These bills have addressed three major carbon management issues:

- Post-injection ownership and liability for subsurface carbon dioxide
- Tax incentives for use of man-made CO_2 in EOR projects
- Permitting and regulatory streamlining

Additional issues that many feel will require future statutory or regulatory clarification include:

- Ownership of subsurface pore space (storage space for CO_2)
- Agency responsible for regulation of geologic CO_2 sequestration
- Responsibility for long-term monitoring, measurement, and verification of injected CO_2

6. The current status of research and technology in the capture and sequestration of carbon dioxide

Existing capture technologies are not cost-effective when considered in the context of sequestering CO_2 from existing coal-fired power plants. CO_2 is currently recovered from combustion exhaust by using amine absorbers and cryogenic coolers. The estimated cost of CO_2 capture using current technology is estimated to be as high as $150 per ton of carbon – much too high for carbon emissions reduction applications. Therefore the U.S. DOE is pursuing evolutionary improvements in existing CO_2 capture systems and also exploring revolutionary new capture and sequestration concepts.

Opportunities for significant cost reductions exist since very little R&D has been devoted to CO_2 capture and separation technologies. Several innovative schemes have been proposed that could significantly reduce CO_2 capture costs compared to conventional processes. "One box" concepts that combine CO_2 capture with reduction of criteria pollutant emissions are being explored as well.

Examples of ongoing research in carbon capture include:

- new materials (e.g., physical and chemical absorbents, carbon fiber molecular sieves, polymeric membranes);
- micro-channel processing units with rapid kinetics;
- CO_2 hydrate formation and separation processes;
- oxygen-enhanced combustion approaches;
- Development of retrofit CO_2 reduction and capture options for existing large point sources of CO_2 emissions such as electricity generation units, petroleum refineries, and cement and lime production facilities;
- Integration of CO_2 capture with advanced power cycles and technologies and with environmental control technologies for criteria pollutants.

The other main area of research is in carbon sequestration (storage). Efforts to store CO_2 are focused on two categories of repositories: Geologic formations and terrestrial ecosystems. Geologic formations considered for CO_2 storage are layers of porous rock deep underground that are "capped" by a layer or multiple layers of non-porous rock above them. Sequestration practitioners drill a well down into the porous rock and inject pressurized CO_2 into it. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow until it encounters a barrier of non-porous rock (cap rock), which can trap the CO_2 and prevent further upward migration.

The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to discern. Research is aimed at developing the ability to characterize a formation before CO_2-injection to be able to predict its CO_2 storage capacity. Another area of research is the development of CO_2 injection techniques that achieve broad dispersion of CO_2 throughout the formation, overcome low diffusion rates, and avoid fracturing the cap rock.

NETL research is focused on three priority types of geologic formations in which CO_2 can be stored: Depleted oil and gas reservoirs; unmineable coal seams; and saline formations. Each presents different opportunities and challenges. Other promising potential avenues for carbon sequestration include injection into basalt and organic rich shales, terrestrial sinks (trees, marginal cropland, wetlands), and ocean injection.

The current status of research and technology of geologic carbon sequestration is, in many respects, in its infancy. While the oil and gas industry has more than 30 years experience injecting CO_2 into oil reservoirs to enhance production, very little has been done with the express purpose of sequestering CO_2 in geologic formations on a commercial scale.

U.S. DOE's Carbon Sequestration Regional Partnerships exist to demonstrate the viability of large-scale capture, transportation, and storage of CO_2 in an economic, safe, and permanent manner. There will be dozens of small scale injection projects (<100,000 tons CO_2), likely followed by larger applications (>1Mtpy CO_2). They are planning to supplement the 25 ongoing geologic injection field tests (1,000 to 10,500 tons of CO_2) across the country with large-volume injections (in the order of 1 Mt per year) of CO_2 in the 2008-2017 timeframe.

7. Identification of marketing opportunities and uses for carbon dioxide as a value-added commodity, the maturity and long-term feasibility of those markets, the potential for carbon utilization relative to the anticipated generation of carbon, and the economic and environmental risks associated with these uses of carbon dioxide

There are numerous current industrial uses for carbon dioxide. The largest uses of CO_2 are:

- CO_2 is used in the metals industry in manufacturing casting molds.
- In MIG/MAG welding; the gas protects a weld from oxidation as it is being made.
- Large quantities are used as a raw material in chemically manufacturing products such as methanol and urea.

- Crushed dry ice is used in "sandblasting" operations to remove surface coatings and tumbling operations to remove "flash" from rubber parts.
- In the food industry, liquid CO_2 is used to decaffeinate coffee (it is a good solvent for many organic compounds). Gaseous CO_2 is used to carbonate drinks, displace air during canning, and prevent fungal and bacterial growth.
- Carbon dioxide is used as an additive to oxygen for medical use as a respiration stimulant.
- As a propellant in aerosol cans, CO_2 replaces more environmentally troublesome alternatives. It can also be used to enhance production in greenhouses, and to neutralize alkaline water.

Unfortunately, the above uses do not result in CO_2 being stored; in all of these applications, the CO_2 is quickly released back into the atmosphere.

The only current commercial use for CO_2 that could result in large volumes being stored is the use of carbon dioxide for EOR in older oil fields and enhanced methane production from unmineable coal seams. According to estimates by the Regional Carbon Sequestration Partnerships more than 82.4 billion metric tons of sequestration potential exists in mature oil and gas reservoirs, and over 180 billion metric tons of sequestration potential exists in unmineable coal seams. This represents over 43 years of storage at the United States' current CO_2 emission rate of approximately six billion metric tons per year. One advantage of this use is that any oil and gas recovered would net against the expense of capturing, compressing, transporting, and injecting the carbon dioxide. The Department of Energy estimates that from 89 billion (short term) to 430 billion (longer term) barrels of oil could be recovered by injecting depleted fields with CO_2.

8. Identification of other uses for carbon dioxide and the feasibility of large-scale implementation of such uses

Some of the potential or proposed commercial uses for CO_2 include enhanced algae growth, conversion to a combustible fuel, and *terra preta*.

Enhancing algae growth uses an enriched stream of carbon dioxide from a power plant. The enhanced growth is accomplished by exposing nutrient-rich algal ponds to sunlight and CO_2 with the algae subsequently used to produce liquid fuels or power. Processes for direct conversion of carbon dioxide into combustible fuels (methane and carbon monoxide) are being researched. These include processes utilizing sunlight and microbial conversion. So far they are preliminary studies and will need substantial further research.

Terra Preta is a potential option for carbon sequestration combined with enhanced biomass production. The approach entails charring of biomass by gasification to produce gaseous fuels, followed by burial of the char for long-term enhancement of soil. This avenue could conceivably be used to significantly enhance the fertility and biomass production rate on, for example, abandoned strip mine lands or other marginal soils that are prevalent in Kentucky.

9. Identification of feasible methods for capturing and transporting carbon dioxide from the generation point to end users, including the construction of carbon dioxide pipelines, rail transportation, or other means, and the positives and negatives for each method

When geologic sequestration sites do not occur immediately below CO_2 sources, CO_2 will have to be transported offsite. Viable options for transport of CO_2 include truck, rail, and pipeline.

The most commonly employed technique for transporting large quantities of CO_2 is by underground pipeline. CO_2 pipelines have been in use since the 1970s to transport CO_2 from natural reservoirs to west Texas for use in EOR. CO_2 pipelines operate at high pressures, where the CO_2 is in a liquid phase. All CO_2 pipelines in current use are made of conventional steel. If the CO_2 is kept free of water, corrosion is not a big problem. Water mixed with the CO_2 can cause serious corrosion problems with normal carbon steel pipe.

CO_2 pipelines have proven to be very safe to operate. They are classified as high volatile/low hazard/low risk per federal regulations. CO_2 does not burn, which eliminates explosion hazards. Ruptures and leaks could occur, and CO_2 could be hazardous if it collects in confined areas, displacing oxygen. But in the 10-year period from 1991 to 2001 there were no CO_2 pipeline-related injuries or deaths in the U.S.

Because of the huge amount of CO_2 and the distances involved, whether or not the CO_2 captured from coal-fired power plants is delivered to an end user or delivered to a location for sequestration the only viable method of transporting CO_2 will be through pipelines. While new facilities which emit large amounts of CO_2 can probably be located near end users or sequestration sites, existing power plants are often located at great distances from them. Large-scale CCS will require a network of pipelines at least equal to the existing interstate natural gas pipeline grid. To establish such a network of pipelines, numerous issues will have to be addressed regarding the siting, permitting, construction and operation of these pipelines.

10. Identification of any issues or concerns relating to carbon dioxide that are unique to Kentucky

The economic impact of a carbon-controlled future on the state of Kentucky, which relies on coal for more than 90% of its electricity, could be significant because other resource options are limited. Kentucky does not have sufficient hydro, wind or solar resources to replace coal-fired baseload generation, given the state of today’s technology. Natural gas prices are more volatile than coal prices and they are projected to escalate as more natural gas-fired generation is constructed elsewhere in the country. Higher energy prices coupled with the loss of coal-related jobs could have a serious impact on our state's economy. Nuclear power is not a statutory option at this time. If it were an option to consider, the capital construction costs are significantly higher than for coal-fired generation. The federal permitting process requires a longer lead time than coal-fired generation.

Any legislation that puts coal at a comparative disadvantage to other sources of fuel to generate electricity would have a serious negative effect on not only the coal industry, but on Kentucky's economic development potential and the citizens and businesses that depend on affordable electricity. As coal is and will continue to be the least-cost fuel for electricity generation, any legislation that adds costs to coal-fired electricity generation that are not also levied against other forms of generation would raise Kentucky's rates disproportionately compared with states having other resources and would thus lessen the differential in cost of electricity that Kentucky currently enjoys with respect to other states.

With Kentucky's long-standing reliance on coal for electricity generation and the resulting relative low electricity rates, there is tremendous potential for the state to benefit from increased emphasis on energy efficiency. Although our electric rates have been among the lowest in the nation, our citizens, businesses, and industries pay higher bills than many states with higher rates.

The subsurface geology of Kentucky is generally favorable for carbon sequestration and CO_2 enhanced oil and gas recovery. The Appalachian Basin in the east and the Illinois Basin in the west contain oil and natural gas fields, and deep saline aquifers for which available data indicates suitability for injection of CO_2. Many of the deeper formations in particular will require additional well data in key areas to fully evaluate their capacity for CO_2 injection and storage. Most of these porous and permeable formations are overlain by thick impermeable shale formations, which provide good seals to contain $CO_{2.}$ Development of the ability to use this abundance of potential storage capacity may be critical to the viability of future coal-fired power plants (and hence, the viability of the Kentucky coal industry and maintaining favorable electricity rates in Kentucky). However, despite the thickness of sedimentary rocks and abundance of oil and gas fields in Kentucky, there are several concerns that will have to be addressed in some areas before sequestration can be implemented.

11. Assessment of long-term risks and uncertainties associated with carbon-management options

In addition to actual physical injection of CO_2, considerable modeling of injection is getting started. Questions which may be addressed by modeling and/or physical injection include:

- What happens to the CO_2 when it is injected? What are the physico-chemical and the chemical processes involved?
- How long can CO_2 remain sequestered underground?

- How much and where can CO_2 be stored in the subsurface locally, regionally, and globally?
- Are there sufficient opportunities for CO_2 -enhanced oil and gas recovery?
- How can a suitable storage site be identified and what are its geologic characteristics?
- What are the methods that we can use to monitor geologically stored CO_2?
- Will a geologic CO_2 storage site leak and how much leakage is acceptable?
- Can a geologic CO_2 storage site be operated safely, and if so, how and for how long?
- Can a CO_2 storage site be remediated if something goes wrong?

Large scale CO_2 management has never been implemented. Consequently, there are a number of unknowns, with attendant risk, at this stage of planning. These unknowns include:

- What are the legal and regulatory issues pertaining to geologic sequestration?
- Who will own, and be liable for, post-injection subsurface carbon dioxide?
- Who owns the subsurface pore space (storage space for carbon dioxide)?
- What are the likely costs of geologic sequestration and can we afford it?
- What government agency will be responsible for regulation of CO_2 sequestration?
- Who will be responsible for long-term monitoring, measurement, and verification of injected CO_2?
- What collateral environmental impacts may be caused by large scale deployment of possible solutions (for instance, from ocean injection)?
- The financial impact due to the unequal effect that carbon management will have on the relative costs of different electric generating options and different industries.
- The pace of development of any of the alternative technologies.

The single greatest long-term risk associated with CO_2 management is the unquantifiable liabilities related to the transportation, injection and storage of enormous quantities of CO_2 in geologic formations. Damage to property, human health, and the environment could occur from accidents, leaks, failure of storage systems and other circumstances where CO_2 might be released into the subsurface, surface or ambient air. A legal and regulatory framework governing CCS needs to be developed that includes specific mechanisms to address or cap these liabilities.

12. Identification of existing collaborative efforts and partnerships developed to address carbon dioxide issues in which Kentucky participates

In addition to the previously mentioned regional carbon sequestration projects, there are a number of collaborative efforts underway in Kentucky. Working closely with utility companies in Kentucky [E-ON US, East Kentucky Power Cooperative (EKPC), Kentucky Power (AEP), Duke Energy and TVA], the University of Kentucky's Center for Applied Energy Research is in the early stages of forming a research alliance called the "Kentucky Consortium for Advanced Power Generation". The purpose of this consortium is to maintain and strengthen Kentucky's comparative advantage as a low-cost producer of electricity, while simultaneously improving the quality of Kentucky's environment, in anticipation of federal limitations on carbon dioxide CO_2. The Governor's Office of Energy Policy has provided funding for the organizational phase of this consortium.

The consortium will build on the successes the CAER is showing with the 0.1MW pilot plant that has been built for post-combustion CO_2 capture. These successes, coupled with financial support from the utilities in Kentucky, have led the CAER to propose a series of slip-stream field investigations at selected utility's plants using a portable 1MW slip-stream post-combustion apparatus. The test sites will be selected based upon system configurations and coal types at the various power plants. This study conducted at a power plant represents a critical step in developing and demonstrating practical technologies for reducing CO_2 emissions from Kentucky's existing fleet of coal-fired power plants. The study will also help train Kentucky's workforce to respond to challenges that will be faced in a carbon-constrained world.

The Kentucky Public Service Commission, as a member of the National Association of Regulatory Utility Commissioners (NARUC), is actively engaged in several committees and workgroups. In July 2007, NARUCs' Board of Directors passed a resolution urging Congress to protect ratepayers and existing state regulatory authority as it considers potential climate-change legislation. Chairman Mark David Goss of the Kentucky Public Service Commission serves as a member of the board of directors of NARUC. PSC Chairman Mark David Goss serves as chairman of NARUC's Clean Coal Technology and Carbon Capture and Storage Subcommittee. The Subcommittee serves three functions: (1) Educate NARUC members about clean coal technologies and carbon capture and storage issues; (2) Identify the barriers and opportunities regarding these technologies; and (3) Serve as a resource for stakeholders to communicate with the various state utility regulators.

Working with NARUC staff, the Subcommittee recently obtained funding from the U.S. Environmental Protection Agency to develop an analysis of regulatory treatment of emission allowances by the states, a primer focusing on advanced coal-fired generation technologies, and a report on prioritizing regulatory issues on carbon capture and storage for state commissioners.

Chairman Goss is also a member of NARUC's Advanced Coal Technology Workgroup. The workgroup has recommended development of risk characterization, risk management, and liability mechanisms to enable the accelerated deployment of carbon capture and storage technologies.

Another collaborative project involves the Kentucky Division of Forestry, which established Kentucky's first tree planting project for carbon sequestration in 2004. A partnership was established with AEP in which the Kentucky Division of Forestry was awarded $96,000 to reforest 400 acres on Green River State Forest. Nearly 174,500 hardwood tree seedlings were planted on the Green River State Forest at the confluence of the Green River and Ohio River in Henderson County. AEP, as part of the U.S.

Department of Energy's Global Climate Challenge Program (GCCP), can offset its carbon emissions by planting forests that will absorb and store carbon. A healthy, vigorously growing forest absorbs more carbon. The Division of Forestry, in managing the state forest as a premier forest stewardship demonstration area, inherently strives for healthy fast growing trees.

Recently the Mountain Association for Community and Economic Development (MACED) began accepting applications for a carbon credits program. Enrollment is open to private forest landowners in the Appalachian region of Kentucky. Second year enrollment will begin in early 2008 and enrollment statewide will be considered. Forest landowners owning 40 acres or more are encouraged to apply. Four requirements must be met in order to be eligible for carbon credit payments. Based on the June 2007 Chicago Climate Exchange (CCX) market price, a forest landowner could expect to receive $4.00 – $5.00 per acre per year dependent on the average age of the trees and the overall condition of the property.

13. Identification of the types of incentives or other government assistance necessary to support the development and implementation of new technologies to capture and sequester carbon.

Prior to a cap and trade system or carbon tax making sequestration of CO_2 economical, a sequestration tax credit should be provided at a level equal to the cost of compressing, transporting, and storing $CO_{2.}$ This would function similarly to a production tax credit for renewable fuels. It would most likely be utilized by industries already separating CO_2 from their production stream. This would provide a source of CO_2 for large scale studies of carbon capture and storage (CCS) prior to enactment of economy wide requirements to cut carbon emissions. The NARUC Advanced Coal Technology Work Group recommends that any GHG policy should include provisions that result in the early and widespread development and deployment of advanced coal technologies.

Any national mandatory policy driver should include provisions that will enable:

- the early deployment of advanced carbon control technologies, particularly CCS;
- a rapid reduction in the cost of CCS systems; and
- a rapid reduction in the energy penalty of carbon capture systems.

Policymakers should judge any broad-based GHG policy by its ability to bring about such developments.

In order to achieve these goals it will be necessary to provide incentives for the deployment of CCS systems. Such incentives could form part of the mandatory policy driver or be pursued through *supplementary policies* that complement broader national GHG policies through increased attention to and incentives for specific key technologies.

A two-pronged approached is necessary to bring about the widespread, accelerated deployment of advanced carbon control technologies, particularly CCS:

1) A national, mandatory policy that limits GHG emissions (the "stick"). Without such a national policy CCS will not be developed and deployed at the speed and scale necessary to enable coal to continue its role in meeting the nation's electricity needs while stabilizing the concentration of CO_2 in the atmosphere at acceptable levels. However, to enable the required rapid development and deployment of CCS technologies:
2) Either as part of the mandatory policy or in the form of supplementary policies, incentives will be needed due to the high current costs and energy penalties of these technologies (the "carrot"). For example, supplemental policies may be needed to correct a policy's inability to ensure sufficient early funding for deployment and needed RD&D.

Incentives Necessary for Sequestration

- Determination of post-injection ownership and liability for subsurface carbon dioxide
- Tax incentives for use of man-made CO_2 in enhanced oil recovery projects
- Permitting and regulatory streamlining
- Resolve ownership issues for subsurface pore space (storage space for CO_2)
- Determine agency responsible for regulation of geologic CO_2 sequestration
- Assign responsibility for long-term monitoring, measurement, and verification of injected CO_2

Union of Concerned Scientists

Gambling with Coal

How Future Climate Laws Will Make New Coal Power Plants More Expensive

by Barbara Freese and Steve Clemmer
Union of Concerned Scientists[1]
September 2006

Abstract
New conventional coal plants are an imprudent financial investment. The world scientific community warns that carbon dioxide (CO_2) emissions from our use of fossil fuels, especially coal, is leading to dangerous global warming. Policies to reduce CO_2 emissions are emerging at every level of government, including in the US Congress, which is actively considering several mandatory, market-based CO_2 proposals with increasing support from the private sector. Laws requiring coal plants to pay to emit CO_2 will be adopted in the next few years, substantially raising the costs of coal power.

Nevertheless, many utilities have proposed investing in new conventional coal plants that will operate for decades, ignoring the economic impact of these virtually inevitable CO_2 reduction laws, perhaps because they believe they will be able to pass these costs on to ratepayers. Utility managers and shareholders should reconsider the financial risks to their companies and customers. Regulators should prevent utilities from making these major investment mistakes by refusing to approve the construction of new conventional coal plants and by requiring them to invest in cleaner alternatives, or at the very least, by warning utilities that CO_2 costs must be borne by their shareholders, not by ratepayers.

Executive summary

It is now virtually inevitable that America will adopt a federal law limiting global warming pollution from power plants. Indeed, given the momentum of emerging policy responses to global warming on the local, state, and regional levels in the United States (as well as internationally), federal legislation will probably be adopted within the next five years. This document discusses why such a law is so likely, what kind of new costs coal plants will face as a result, and how these future costs make building new, conventional coal plants a reckless financial gamble.

[1] We would like to thank the Garfield Foundation for providing funding for this work.

The need for legal limits to America's global warming pollution is undeniable. Scientists have long known that the burning of fossil fuels releases heat-trapping carbon dioxide (CO_2) into the air, where it is building up. Scientific concern that this buildup could disrupt our climate has been growing steadily since the late 1980s. Every year, the science has become even more compelling: Earth continues to experience record-breaking warmth, humans' dominant role in this warming becomes clearer, and we see the planet reacting to the warming in troubling ways.

Most developed nations have responded to this evidence by ratifying the Kyoto Protocol, which requires them to reduce their CO_2 emissions. The United States has not ratified Kyoto, but as the world's largest emitter of heat-trapping gases by far, it is under increasing international pressure to act. Along with almost every other nation in the world, the United States did ratify the 1992 Framework Convention on Climate Change, a treaty with the objective of preventing dangerous global warming. And in 2005 the U.S. Senate passed a landmark resolution stating that mandatory federal CO_2 limits should be enacted. Several proposals establishing CO_2 limits are being considered by Congress, and a series of hearings have been held in the Senate to discuss the design of such limits.

The congressional response is being spurred in part by a growing policy response on the state and regional level, including the regional CO_2 limits and trading system being established by eight northeastern states. Within the last year or two, a substantial number of major companies—including half of America's 10 largest power companies—have called for such regulation, and most utility executives believe that such regulation is coming.

There is no doubt that the burden of future CO_2 regulations will fall heavily on coal plants. Power plants are the largest source of U.S. CO_2 emissions, accounting for 39 percent of the nation's energy-related emissions, and most of these emissions come from coal plants. In fact, coal plants produce one-third of America's CO_2 emissions—about the same amount as all our cars, SUVs, trucks, buses, planes, ships, and trains combined.[2]

Each new coal plant represents an enormous long-term increase in global warming emissions. A 500-megawatt (MW) plant, for example, produces the annual global warming emission equivalent of roughly 600,000 cars,[3] but unlike a car, a coal plant is designed to operate for 40 to 50 years (and they often operate even longer). Global warming cannot be effectively addressed without limiting coal plant emissions, so the congressional proposals under consideration all target coal plants.

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[2] U.S. Environmental Protection Agency (EPA), "Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2004," April 2006. Online at *http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html*. Also see U.S. Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2004*, December 2005, 20–22. Online at *ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057304.pdf*.

[3] Based on average annual emissions of 13,500 lbs/vehicle as estimated by the EPA (*http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterToolsGHGCalculator.html*) and annual emissions of 4.1 million tons from a 500 MW plant as estimated by the Public Service Commission of Wisconsin (*http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf*).

It is widely expected that future CO_2 regulations will take the form of a "cap-and-trade" system, similar to the national law for controlling the sulfur dioxide (SO_2) emissions that cause acid rain. Such a system would establish a national cap on CO_2 emissions, and power plant operators would have to own an "allowance" for each ton of CO_2 they emit. Operators could buy and sell these allowances for a price established by market forces. Economists believe such a cap-and-trade system would provide the flexibility and incentives to meet a given CO_2 cap at the lowest cost.

Utilities are increasingly quantifying the risk they face from future CO_2 allowance costs in their planning documents. In some cases, they do so because state regulators demand it, and in other cases they do it at their own initiative. Studies forecasting the price of future CO_2 allowances range widely, but useful estimates are emerging from the literature. These estimates indicate that coal plants face CO_2 costs that will increase the cost of coal power substantially and perhaps severely. Mid-range projections of CO_2 allowance prices could increase the cost of electricity from the average new coal plant by roughly half.[4] Because coal plants are designed to last for decades, these added financial costs—along with the environmental costs created by coal plants—will be borne by both the present and future generations.

These allowance price forecasts generally assume the adoption of federal policies that aim for modest CO_2 emission reductions at best. However, the science now indicates that if we hope to avoid dangerous global warming, developed nations will need to reduce their CO_2 emissions dramatically—as much as 60 to 80 percent or more—by 2050.[5]

This evidence has prompted governments including California, New Mexico, the New England states, the eastern Canadian provinces, the United Kingdom, and the European Union to adopt long-term CO_2 emission reduction targets in the 60 to 80 percent range. It is therefore reasonable to expect that even if the emission cap initially enacted establishes only modest, short-term targets, it will be followed with increasingly strict national caps in the decades ahead—that is, throughout the operating lifetime of coal plants proposed today.

Meanwhile, climate policies are likely to accelerate the development of energy resources that significantly reduce heat-trapping emissions (reducing the cost of these resources relative to coal) and the development of energy efficiency technologies (reducing electricity demand below currently projected levels). In all likelihood, these changes will improve the economics of coal alternatives just as ever-tightening emission caps are worsening the economics of coal plants.

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[4] For CO_2 price projections see Synapse Energy Economics, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," May 18, 2006. Online at *http://www.synapse-energy.com*.

[5] European Environment Agency, "Climate Change and a European Low-Carbon Energy System," Copenhagen, 2005. Online at *http://reports.eea.eu.int/eea_report_2005_1/en/Climate_change-FINAL-web.pdf*.

Given these highly foreseeable trends, why are so many utilities still proposing to lock themselves into capital-intensive coal plants rather than investing in options that do not expose them to such financial risk? These utilities may be betting on their ability to pass the risk on to ratepayers in the form of higher electric rates—the same way they routinely pass through environmental compliance costs today. Utilities holding this belief have little incentive to assess and avoid the risks of future CO_2 regulation. That places on state utilities regulators an enhanced responsibility to assess for themselves the risks associated with gambling huge amounts of money on a large, multi-decade source of CO_2 emissions just as the nation is about to launch a large, multi-decade effort to reduce CO_2 emissions that will surely target coal power.

Utilities may also be ignoring these political developments under the reckless assumption that any plant built before a federal CO_2 cap is adopted will be allocated allowances for free. This gamble ignores the growing opposition to granting such a windfall to utilities (particularly those that could avoid new allowance costs by simply investing in alternatives to coal). The Northeast Regional Greenhouse Gas Initiative (RGGI) model rule, for example, requires that at least 25 percent of allowances be auctioned rather than allocated,[6] and Vermont, the first Northeast state to pass enabling legislation, requires *all* allowances to be auctioned.[7] In fact, 28 different stakeholders in the RGGI model rule draft—including businesses, consumer groups, environmental organizations, state agencies, and an electricity distribution company—supported auctioning 50 to 100 percent of allowances.[8]

At the federal level, Senators Pete Domenici (R-NM) and Jeff Bingaman (D-NM) issued a white paper describing the design elements of a mandatory system to reduce emissions. The paper notes that auctioning off all allowances would minimize the costs to the U.S. economy as a whole, streamline the administrative process, and avoid unintended competitive advantages and windfall profits for certain market participants.[9] A recent Wall Street study also predicts that the United States will have an auction-based rather than allocation-based cap-and-trade system.[10]

If regulators do authorize the construction of a new coal plant, they should notify the utility up front that it will not be allowed to pass future CO_2 compliance costs on to ratepayers. The last time the nation's utilities embarked on a large-scale campaign to build new baseload plants (plants that operate most of the time) was the 1960s and 1970s; the result was scores of abandoned nuclear projects and a great deal of excess generating capacity. Disputes over whether ratepayers or utility shareholders should pay for these

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[6] Regional Greenhouse Gas Initiative (RGGI) Model Rule, subpart XX-5.3. Online at *http://www.rggi.org/docs/model_rule_8_15_06.pdf*.
[7] The Vermont law (H. 860) is online at *http://massclimateaction.org/RGGI/VTRGGISignedMay06.pdf*.
[8] Environment Northeast, Natural Resources Defense Council, and Pace Law School Energy Project, "Summary of Comments on the RGGI Model Rule Draft," 2006.
[9] Sen. Pete V. Domenici and Sen. Jeff Bingaman, "Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System," February 2006.Online at *http://www.nam.org/s_nam/bin.asp?CID=43&DID=236483&DOC=FILE.PDF*.
[10] Hugh Wynne, "U.S. Utilities: The Prospects for CO_2 Emissions Limits in the United States and Their Implications for the Power Industry," Bernstein Research, April 19.

investment mistakes led to a series of decisions requiring shareholders to pay for at least a portion of the losses. Those decisions stressed the importance of forcing utilities to assume financial risk in order to give them an incentive to track events that could increase the cost of construction projects and to reassess the viability of those projects as conditions warrant.

Given the momentum now driving the nation toward CO_2 limits—and the substantial impact such limits will have on the cost of coal power—it has never been more critical to ensure that utility managers are staying abreast of current developments. Placing the financial risk of future CO_2 costs on shareholders, clearly and up front, will create that incentive. This regulatory approach is not only fully consistent with rate-making principles, but also builds on the lessons learned from the expensive investment mistakes of the past.

I. Scientific evidence clearly establishes the need for policies limiting CO_2 emissions now and reducing them dramatically over a period of decades.

A. The scientific consensus about the reality of global warming is strong and growing stronger.

The world scientific community spoke with one voice recently to deliver an unprecedented and remarkably pointed message to world leaders. Eleven of the world's most respected national science academies, including the U.S. National Academy of Sciences (NAS), issued this joint statement in anticipation of the 2005 G8 Summit:

> *"Climate change is real. There will always be uncertainty in understanding a system as complex as the world's climate. However, there is now strong evidence that significant global warming is occurring."*[11]

The statement called on world leaders to acknowledge that "the threat of climate change is clear and increasing," and urged all nations "to take prompt action to reduce the causes of climate change."[12]

The NAS is generally considered America's preeminent scientific association. It was chartered by Congress in 1863 and tasked with the role of advising the nation on scientific matters. Its 2,000 members—all elected to the academy in recognition of their distinguished achievements in original research—include the nation's most respected scientists; roughly 10 percent have won a Nobel Prize.[13] When the Bush administration

[11] The "Joint Science Academies' Statement: Global Response to Climate Change" was issued by the NAS and its counterpart academies in Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, and the United Kingdom. Online at *http://nationalacademies.org/onpi/06072005.pdf*.
[12] Ibid.
[13] See the NAS website: *http://www.nasonline.org/site/PageServer?pagename=ABOUT_main_page*.

took office in 2001, it asked the NAS for confirmation that our heat-trapping emissions are causing global warming, and it received that confirmation.[14]

This joint statement follows a growing number of statements and reports reflecting concern about global warming from the NAS, the American Geophysical Union, the American Association for the Advancement of Science, the American Meteorological Society—indeed every scientific association in the nation whose membership has expertise directly relevant to the issue.[15] The consensus on the reality of climate change is so strong that a review of 928 papers published in peer-reviewed scientific journals between 1993 and 2003 did not find a single paper that disagreed with the consensus view.[16]

The scientific consensus has been gaining strength at the international level as well. Since 1988, thousands of scientists have been part of a formal process—under the auspices of the Intergovernmental Panel on Climate Change (IPCC)—for methodically and collectively looking at the climate science and publishing reports to help the world's policy makers determine the scope of the global warming threat. The IPCC has published three major assessments to date (1990, 1995, and 2001), each time expressing greater concern about the certainty and potential danger of global warming.[17] Given the record-breaking warmth the planet has continued to experience since the 2001 IPCC report and subsequently published scientific assessments,[18] it is widely expected that the IPCC's upcoming 2007 report will continue that trend.[19]

Evidence that we are changing the climate and that the planet is responding in worrisome ways is now so strong that many who have dismissed global warming in the past have recently changed positions. Prominent members of the media who formerly declared themselves skeptical of the threat have quite publicly "switched sides."[20] Even

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[14] NAS, "Climate Change Science: An Analysis of Some Key Questions," 2001. Online at http://fermat.nap.edu/books/0309075742/html.

[15] Ibid. Also see NAS, "Understanding and Responding to Climate Change: Highlights of National Academies Reports," 2006 (online at http://dels.nas.edu/basc/Climate-HIGH.pdf); American Geophysical Union, "Human Impacts on Climate," December 2003 (online at http://www.agu.org/sci_soc/policy/climate_change_position.html); Atlas of Population and Environment by the American Association for the Advancement of Science, "Climate Change" (online at http://www.ourplanet.com/aaas/pages/atmos02.html); American Meteorological Society Council, "Climate Change Research: Issues for the Atmospheric and Related Sciences," February 9, 2003, *Bulletin of the American Meteorological Society* 84, 508–515 (online at http://www.ametsoc.org/POLICY/climatechangeresearch_2003.html).

[16] Naomi Oreskes, "Beyond the Ivory Tower: The Scientific Consensus on Climate Change," *Science*, December 3, 2004, 1686. Online at http://www.sciencemag.org/cgi/content/full/306/5702/1686.

[17] Intergovernmental Panel on Climate Change (IPCC), "16 Years of Scientific Assessment in Support of the Climate Convention," December 2004. Online at http://www.ipcc.ch/about/anniversarybrochure.pdf.

[18] For example, see Scientific Symposium on Stabilisation of Greenhouse Gases, "Avoiding Dangerous Climate Change," Executive Summary of the Conference Report, February 1-3, 2005, 2. Online at http://www.defra.gov.uk/environment/climatechange/internat/dangerous-cc.htm.

[19] Roger Harrabin, "Consensus Grows on Climate Change," BBC News, March 1, 2006. Online at http://news.bbc.co.uk/1/low/sci/tech/4761804.stm.

[20] Gregg Easterbrook recently wrote in the *New York Times*, "[a]s an environmental commentator, I have a long record of opposing alarmism. But based on the data I'm now switching sides regarding global

ExxonMobil, which has for years disputed the mainstream climate science more aggressively than any corporation in America, now admits "that the accumulation of greenhouse gases in the Earth's atmosphere poses risks that may prove significant for society and ecosystems. We believe that these risks justify actions now, but the selection of actions must consider the uncertainties that remain."[21] The company continues to exaggerate the uncertainties, to fund groups that cast doubt on the science (to the growing dismay of investors[22]), and to resist government regulation, but the science is now so strong that it can no longer deny that the risks justify an immediate response.[23]

B. The evidence establishes that global warming is already harming the planet, and that we face much greater levels of damage in the century ahead.

The basics of global warming science have been understood for a long time. Heat-trapping or "greenhouse" gases, of which CO_2 is the most important, allow the sun's light to penetrate to Earth's surface, where some of it is absorbed and converted into heat. These gases then prevent that heat from radiating back out to space, thereby keeping the planet warm enough to support life.

When we burn fossil fuels, the carbon in those fuels is converted into CO_2; since coal contains the most carbon, it creates the most CO_2 for every unit of energy released.[24] Humans have emitted enough CO_2 to raise background concentrations of this critical heat-trapping gas by about one-third above pre-industrial levels, and concentrations continue to rise.[25] Once concentrations rise, it takes centuries for natural processes to bring them back down again.[26]

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warming, from skeptic to convert." ("Finally Feeling the Heat," May 24, 2006. Online at http://select.nytimes.com/gst/abstract.html?res=F40B1EF63B5A0C778EDDAC0894DE404482; subscription required). A few days earlier, Michael Shermer wrote in *Scientific American*, "environmental skepticism [on climate change] was once tenable. No longer. It is time to flip from skepticism to activism." ("The Flipping Point: How the Evidence for Anthropogenic Global Warming Has Converged to Cause this Environmental Skeptic to Make a Cognitive Flip," June 2006, 28. Online at http://www.sciam.com/article.cfm?articleID=000B557A-71ED-146C-ADB783414B7F0000&sc=I100322.)

[21] ExxonMobil, 2005 Corporate Citizenship Report, May 2006, 22. Online at http://www.exxonmobil.com/Corporate/Citizenship/citizenship.asp.

[22] Andrew Logan and David Grossman, "ExxonMobil's Corporate Governance on Climate Change," CERES and Investor Network on Climate Risk, May 2006, 2. Online at http://www.ceres.org/pub/docs/Ceres_XOM_corp_gov_climate_change_052506.pdf.

[23] Other major oil companies publicly accepted the reality of climate change years ago, and are more direct in their recognition of the risks it poses. The head of BP Amoco said to the British House of Lords in 2002, "Very few people now deny that climate change is a serious risk to the whole of the world" (online at http://www.bp.com/genericarticle.do?categoryId=98&contentId=2000291). Also see the climate statements on the websites of Royal Dutch Shell (www.shell.com) and Chevron (www.chevron.com).

[24] Coal contains nearly 90 percent more carbon per unit of energy than natural gas. However, a new conventional (supercritical) coal power plant produces nearly 150 percent more CO_2 than a new natural gas combined-cycle power plant, which is much more efficient. Based on data from EIA, *Assumptions to Annual Energy Outlook 2006*, Table 38, March 2006, 73. Online at http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2006).pdf.

[25] IPCC Third Assessment Report (TAR), Climate Change 2001: Report of Working Group 1, Summary for Policymakers, 7. Online at http://www.ipcc.ch.

[26] Ibid, 17.

In recent years, scientific concern over global warming has grown both because our understanding of Earth's climate has improved and because the warming trend has continued. The National Aeronautics and Space Administration (NASA) reports that 2005 was the warmest year on record.[27] The five warmest years have all occurred since 1997 (including each of the last four years).[28] In 2001 the IPCC concluded that global average temperatures rose 0.6 degree Celsius (1.1 degrees Fahrenheit) in the twentieth century.[29] However, due to steady warming in this century, total warming over the last 100 years is now up to 0.8 degree Celsius (1.4 degrees Fahrenheit), with most of that increase (0.6 degree Celsius or 1.1 degree Fahrenheit) occurring in just the last 30 years.[30] Scientists have a high level of confidence that the present time is warmer than any period in at least 400 years.[31]

Scientists have been looking for natural causes that would explain the steep warming trend of recent years and have been unable to find them; indeed, it appears that natural causes alone (e.g., solar variation and volcanic activity) should have led to stable or slightly cooler average global temperatures in recent decades.[32] Computer models can only duplicate the recent warming by including today's phenomenally high concentrations of heat-trapping gases, especially CO_2.[33] Figure 1 compares today's CO_2 levels with those occurring over the last 400,000 years. New ice core data go back even further, and show that global CO_2 levels are 27 percent higher than they have been at any time in the past 650,000 years.[34]

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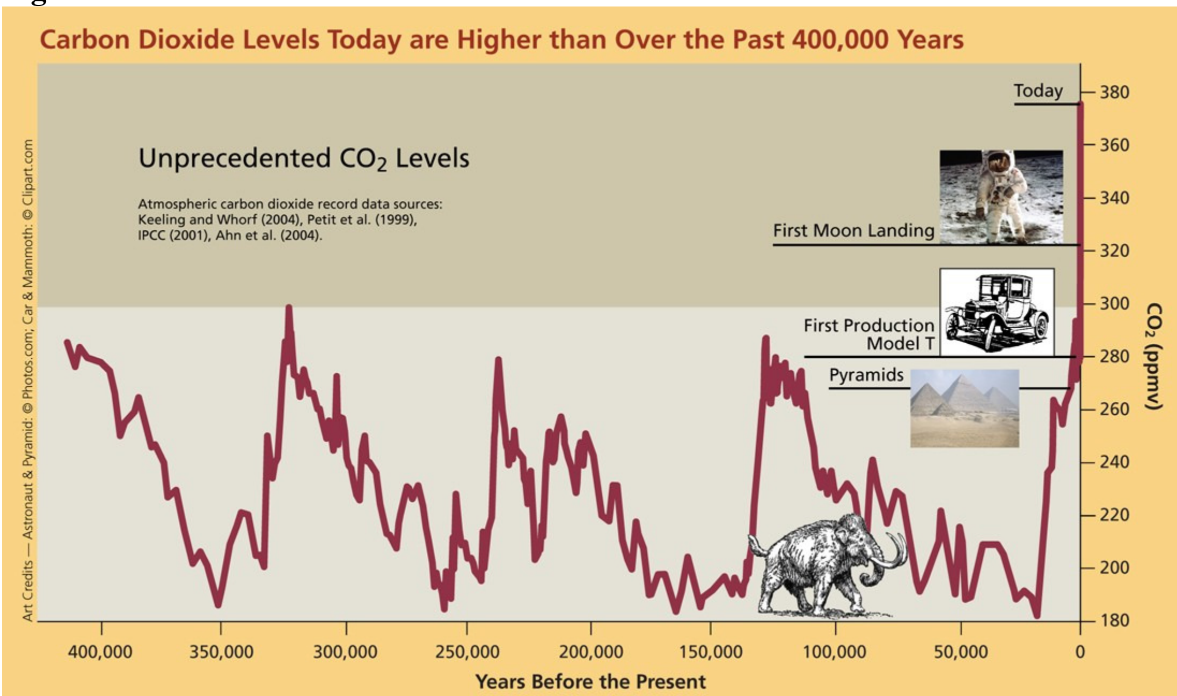
[27] National Aeronautics and Space Administration (NASA), "2005 Warmest Year in Over a Century," January 24, 2006. Online at http://www.nasa.gov/vision/earth/environment/2005_warmest.html.
[28] Ibid.
[29] IPCC TAR, Summary for Policymakers, 2.
[30] NASA, 2006.
[31] National Research Council, *Surface Temperature Reconstructions for the Last 2000 Years*, National Academies Press, 2006, 3. Online at http://www.nap.edu/catalog/11676.html#toc.
[32] IPCC TAR, Summary for Policymakers, 10–11.
[33] Ibid.
[34] Urs Siegenthaler, et al., "Stable Carbon Cycle-Climate Relationship during the Late Pleistocene," 2005, *Science* 310:1313–1317.

Figure 1



Sources: UCS, "Past, Present and Future Temperatures: the Hockeystick FAQ," online at http://www.ucsusa.org/global_warming/science/hockeystickFAQ.html.

Other geologic evidence indicates that current CO_2 levels are probably higher than at any time in the last 20 million years.[35] Projections show that in the years ahead, unless actions are taken to reduce emissions, CO_2 levels could rise to 750 parts per million by volume (ppmv) or higher[36]—well beyond the scale used in Figure 1. In other words, we have already dramatically increased the atmospheric concentrations of a gas that plays a critical role in determining Earth's climate, and much more dramatic changes lie ahead if current trends continue.

The consequences of global warming are now evident around the world, and in many respects Earth is responding to the warming at a faster rate than scientists predicted just a few years ago. The effects of climate change are now visible in most ecosystems and appearing more rapidly than predicted.[37] Recent studies have suggested a link between global warming, higher sea surface temperatures, and an unexpected increase in hurricane strength.[38] Mountain glaciers are in widespread retreat, enormous ice shelves in

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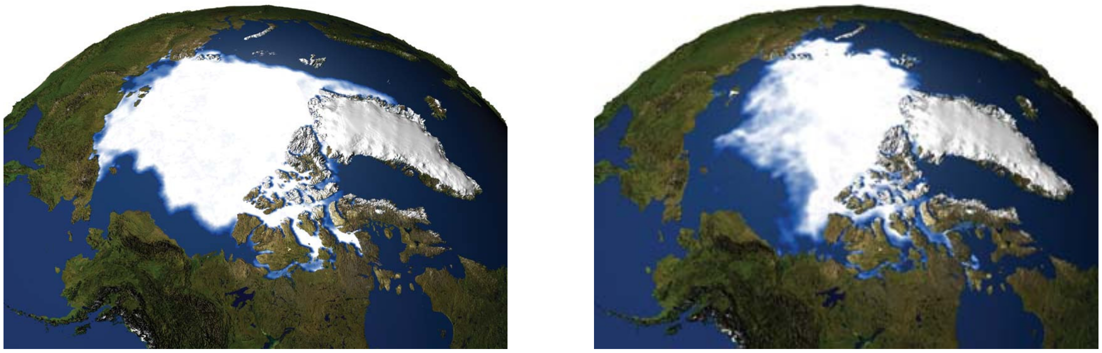
[35] IPCC TAR, Summary for Policymakers, 7.
[36] Ibid., 14.
[37] Hans Joachim Schellnhuber, ed., *Avoiding Dangerous Climate Change*, Chapter 12, Cambridge University Press, 2006. Online at http://www.defra.gov.uk/environment/climatechange/internat/dangerous-cc.htm.
[38] Kerry Emanuel, "Increasing Destructiveness of Tropical Cyclones Over the Past 30 Years," August 4, 2005, *Nature* 436:686 (online at http://www.nature.com/nature/journal/vaop/ncurrent/abs/nature03906.html); Georgia Institute of Technology, "Hurricanes are Getting Stronger, Study Says," press release, September 15, 2005 (online at

Antarctica have collapsed with surprising suddenness, and Arctic permafrost and northern polar sea ice are melting dramatically.[39] Satellites show that perennial sea ice in the Arctic shrunk at a rate of nine percent per decade between 1979 and 2003 (Figure 2).

Figure 2: Arctic Sea Ice Is Retreating



Arctic sea ice in 1979 **Arctic sea ice in 2003**

Source: NASA Goddard Space Flight Center, online at *http://earthobservatory.nasa.gov/Newsroom/NewImages/images.php3?img_id=16340*.

Earth's response to the warming we have experienced thus far increases concerns about how the planet will respond to the much greater warming expected in the century ahead. The IPCC's 2001 assessment predicts warming of another 1.5 to 5.8 degrees Celsius (2.7 to 10.4 degrees Fahrenheit) by 2100.[40] Figure 3 compares this warming with observed temperatures during the previous century and with estimated temperatures of the last 1,000 years.

The range of warming estimates for the next century reflects uncertainties about Earth's climate system as well as uncertainty about the future rate at which heat-trapping gases will be emitted. Recent studies of how natural systems release more heat-trapping gases in response to warming, amplifying the effect of human-made emissions, suggest the 2001 predictions may be conservative.[41]

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http://www.gatech.edu/news-room/release.php?id=654); National Center for Atmospheric Research, "Global Warming Surpassed Natural Cycles in Fueling 2005 Hurricane Season, NCAR Scientists Conclude," press release, June 22, 2006.

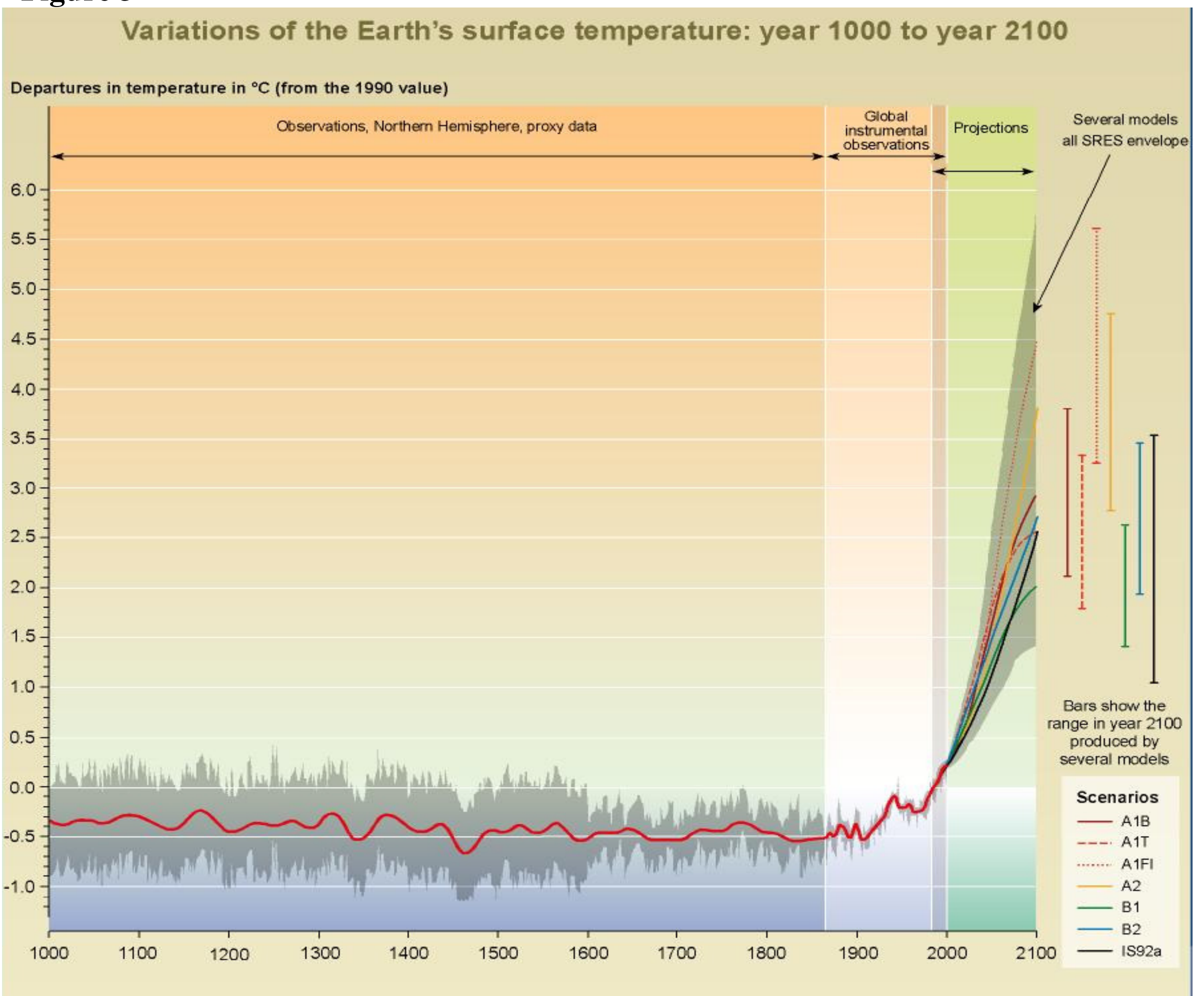
[39]IPCC TAR, Summary for Policymakers, 4; Arctic Climate Impact Assessment: Impacts of a Warming Arctic, Cambridge University Press, 2004 (online at *http://amap.no/acia*); Ice shelf collapses described by the National Snow and Ice Data Center (online at *http://nsidc.org/sotc/iceshelves.html*).

[40] IPCC TAR, Summary for Policymakers, 13.

[41]Margaret S. Torn and John Harte, "Missing Feedbacks, Asymmetric Uncertainties, and the Underestimate of Future Warming," 2006, *Geophysical Research Letters* 33:L10703; Lawrence Berkeley National Laboratory, "Feedback Loops in Global Climate Change Point to a Very Hot 21st Century," press release, May 22, 2006 (online at *http://www.lbl.gov/Science-Articles/Archive/ESD-feedback-loops.html*); American Geophysical Union, "Greenhouse Gas/Temperature Feedback Mechanism May Raise Warming Beyond Previous Estimates," press release, May 22, 2006 (online at *http://www.agu.org/sci_soc/prrl/prrl0617.html*).

Moreover, the NAS and others warn that future warming could occur in abrupt and unpredictable ways. Evidence of past climate changes show the planet has a history of quickly lurching from one climate pattern to another in a way that would make it far harder for nature and society to adapt.[42]

Figure 3



Source: IPCC, "Climate Change 2001:Synthesis Report," Summary for Policymakers, 34.

C. Evidence indicates that dramatic reductions in CO_2 levels will be required in the decades ahead.

Currently, much of the scientific and policy discussion occurring globally focuses on how deeply and quickly CO_2 emissions need to be cut in order to avoid triggering dangerous global warming.[43] The international community has been treaty-bound to work

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[42]National Research Council, *Abrupt Climate Change: Inevitable Surprises*, National Academies Press, 2002. Online at http://www.nap.edu/catalog/10136.html?onpi_newsdoc121101.
[43] Scientific Symposium on Stabilisation of Greenhouse Gases, 2005.

toward this goal since the Framework Convention on Climate Change was adopted in 1992 and ratified by 188 nations (including the United States).[44]

Evidence of the dangers associated with warming greater than two degrees Celsius above pre-industrial levels has been compelling enough to persuade the European Union (EU) to adopt the goal of limiting planetary warming to this level.[45] Studies show that to have a reasonable chance of achieving this goal, net heat-trapping emissions for both developed and developing countries must be reduced at least 15 to 50 percent below 1990 levels by 2050.[46] The European Parliament has adopted a resolution pushing for developed nations to reduce emissions 30 percent by 2020 and 60 to 80 percent by 2050.[47] The United Kingdom adopted a similar target in 2003: 20 percent reductions by 2010 and 60 percent by 2050.

In this country, two states have already adopted similarly ambitious goals. California has adopted a target of reducing heat-trapping emissions by 80 percent (below 1990 levels) by 2050,[48] and New Mexico seeks a 75 percent reduction (below 2000 levels) by 2050.[49] A regional goal was set in 2001 when the Conference of New England Governors and Eastern Canadian Premiers adopted a long-term target of reducing global warming emissions 75 to 85 percent below 2001 levels.[50]

In the discussion that follows it is important to keep this science in mind. Most of the policies currently in place or being debated, internationally and domestically, aim to achieve relatively modest targets that will have to be followed with more aggressive reductions in the years ahead if we are to avoid dangerous warming over the long term. Today's policy proposals must therefore be seen as the first steps in a much longer global process.

Ultimately, emission reductions of the magnitude needed will require a historic, worldwide transition away from the energy technologies that we rely on today, and particularly away from conventional coal plants, during the next four and a half decades—roughly during the operating lifetime of a new coal plant.

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[44] Framework Convention on Climate Change," Article 2. Online at *http://unfccc.int/resource/docs/convkp/conveng.pdf*.
[45] European Environment Agency, 2005, 10.
[46] European Environment Agency, 2005, 7 and Chapter 3.
[47] European Parliament Resolution on Climate Change, January 18, 2006. Online at *http://www.europarl.europa.eu/omk/sipade3?PUBREF=-//EP//TEXT+TA+P6-TA-2006-0019+0+DOC+XML+V0//EN&L=EN&LEVEL=1&NAV=S&LSTDOC=Y&LSTDOC=N*.
[48] Executive Order S-3-05, June 1, 2005. Online at *http://www.climatechange.ca.gov/index.html*.
[49] Office of Governor, State of New Mexico, "Governor Bill Richardson Announces Historic Effort to Combat Climate Change," press release, June 9, 2005. Online at *http://www.governor.state.nm.us/press/2005/june/060905_3.pdf*.
[50] New England Governors/Eastern Canadian Premiers, "Climate Change Action Plan 2001," August 2001. Online at *http://www.neg-ecp-environment.org/page.asp?pg=46*.

II. The global warming policy response is mounting at every level.

A. Other developed nations are deepening their commitments to emission cuts.

The global policy response to climate change has increased along with scientific concern. As noted above, in 1992 the United States and most other nations entered into the Framework Convention on Climate Change. That treaty commits developed nations to adopt policies limiting global warming emissions, but its emission reduction target is not binding.[51] The world community then negotiated the Kyoto Protocol, under which developed nations must reduce their emissions an average of five percent below 1990 levels by the period 2008 to 2012. The protocol went into effect in February 2005 despite the United States' refusal to ratify it.

Almost every other developed nation did ratify Kyoto, so that currently nearly half of the global economy is committed to emission reductions under its provisions.[52] Many nations, particularly within the EU, have already adopted mandatory emission limits. The EU itself is limiting CO_2 emissions with a multinational cap-and-trade system, a market-based regulatory approach pioneered in the United States (see part II, section C), and the European Parliament has also endorsed steep, long-term emission reductions.

The United States' refusal to ratify Kyoto or otherwise limit its global warming emissions leaves it nearly isolated within the developed world—a conspicuous position for a country that is the world's richest and also emits roughly one-quarter of the world's heat-trapping emissions, far more than any other nation.[53] The only other developed country that has refused to be bound by Kyoto is Australia.[54]

Over the years, pressure has mounted on the United States to reduce its emissions. At the 2005 G8 Summit, climate change was at the top of the agenda, and the United States was persuaded to sign a statement pledging to "act with resolve and urgency" in reducing emissions.[55] In November 2005, the European Parliament passed a resolution stating that it "[d]eplores the non-implementation by the current U.S. administration" of the Framework Convention and America's failure to ratify Kyoto.[56]

Industrial nations currently subject to the Kyoto limits helped sustain the protocol's momentum by agreeing in December 2005 to negotiate deeper cuts in global

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[51] Framework Convention on Climate Change, article 4, section 2(a).

[52] Innovest Strategic Value Advisors, "Carbon Disclosure Project 2005," 19. Online at *http://www.cdproject.net/aboutus.asp*.

[53] EPA, Global Warming Emissions: Inventory. Online at *http://yosemite.epa.gov/OAR/globalwarming.nsf/content/EmissionsInternationalInventory.html*.

[54] The status of each nation's ratification of the Kyoto Protocol is available on the United Nations Framework Convention on Climate Change website (*http://unfccc.int/essential_background/kyoto_protocol/status_of_ratification/items/2613.php*).

[55] Gleneagles Communiqué, "Climate Change, Energy, and Sustainable Development," July 2005. Online at *http://www.fco.gov.uk/Files/kfile/PostG8_Gleneagles_Communique.pdf*.

[56] European Parliament, "Winning the Battle Against Global Climate Change," (2005/2049(INI)), November 16, 2005. Online at *http://www.europarl.eu.int/news/expert/infopress_page/064-2439-320-11-46-911-20051117IPR02438-16-11-2005-2005-false/default_en.htm*.

warming emissions for the years after Kyoto compliance ends in 2012.[57] As these and other nations deepen and extend their commitments to mandatory emission cuts, pressure will continue to increase on the United States to do likewise.

B. U.S. states, regions, and cities are enacting their own climate policies.

In the absence of federal limits on heat-trapping emissions, many states have moved forward with their own climate-related policies, including cap-and-trade systems now emerging on both coasts. The most developed of these is the Regional Greenhouse Gas Initiative (RGGI) being undertaken by several northeastern and mid-Atlantic states. In December 2005, Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont formally agreed to launch the nation's first regional program imposing a mandatory cap on heat-trapping emissions from power plants.[58] In April 2006, Maryland joined RGGI as well.[59] Under the agreement, beginning in 2009, the states will stabilize power plants' CO_2 emissions and then cut them 10 percent by 2019.[60] The RGGI model rule was adopted in August 2006 to implement the agreement.[61]

On the West Coast, the California legislature passed a bill on August 31, 2006 that sets in place the nation's most comprehensive, economy-wide global warming emissions reduction program. The bill requires the state's global warming emissions to be reduced to 1990 levels by 2020. This reduction will be accomplished through an enforceable statewide cap on global warming emissions that will be phased in starting in 2012. The bill would also coordinate the efforts of various state agencies, including a pending proceeding at the Public Utilities Commission to establish a load-based cap on the three large investor-owned utilities as well as other jurisdictional utilities in the state. Governor Schwarzenegger has indicated that he will sign the bill into law.[62]

California has also taken the lead in fighting climate change by requiring utilities to make aggressive investments in energy efficiency as well as factor future CO_2 regulatory costs into their resource choices (see part V, section A) and by pursuing a performance standard for global warming emissions that would prevent the procurement of power from conventional coal plants.[63] Other efforts California has taken to reduce global warming emissions include the adoption of motor vehicle standards requiring a 30

[57] Union of Concerned Scientists, "World Moves Forward on Global Warming, Bush Administration Stays Behind," press release, December 10, 2005. Online at *http://www.ucsusa.org/news/press_release/world-moves-forward-on-global-warming-MONTREAL.html*.
[58] See the RGGI website (*www.rggi.org*).
[59] *New York Times*, "Pollution Pact Gets Maryland as 8th Member," April 7, 2006. Online at *http://select.nytimes.com/search/restricted/article?res=FA0E15FD3A540C748CDDAD0894DE404482*.
[60] RGGI Memorandum of Understanding.
[61] Regional Greenhouse Gas Initiative (RGGI) Model Rule. Online at *http://www.rggi.org/docs/model_rule_8_15_06.pdf*.
[62] *Sacramento Bee*, "Schwarzenegger, lawmakers strike deal on greenhouse gases," August 31, 2006. Online at http://www.sacbee.com/content/politics/story/14312261p-15214839c.html.
[63] California PUC, "Policy Statement on Greenhouse Gas Performance Standards," April 12, 2006. Online at *http://www.cpuc.ca.gov/word_pdf/REPORT/50432.doc*.

percent reduction in CO_2 emissions from vehicles by the period 2013 to 2016.[64] As of June 2006, 10 other states plus Canada—representing approximately one-third of automobile sales in North America—had adopted California's standards.[65]

These efforts are part of a wider trend among states to respond to global warming. Twenty states and the District of Columbia, for example, have already adopted renewable energy standards covering approximately 40 percent of the electricity used in the United States,[66] partly in response to global warming. Massachusetts, New Hampshire, Oregon, and Washington have already passed laws limiting power plant CO_2 emissions or requiring plant owners to purchase offsets.[67] California, Oregon, and Washington have also joined forces on the West Coast Governors' Global Warming Initiative, which involves a variety of steps for reducing global warming emissions.[68]

The policy response to climate change is also accelerating at the local level. Mayors of more than 270 cities, representing more than 48 million Americans, have endorsed the US Mayors Climate Protection Agreement. Under this agreement they commit to working within their own communities to achieve the emission reduction targets of the Kyoto Protocol, and to urge the federal government to adopt a global warming emission trading system.[69] More than 150 local governments participate in another initiative to inventory their heat-trapping emissions, develop emission reduction targets, and implement policies to meet them.[70]

All of these state and local efforts increase the calls for and the likelihood of a climate response at the federal level, which would avoid a patchwork of different standards around the nation.

C. Congress is moving toward mandatory cap-and-trade CO_2 limits.

Momentum behind mandatory federal limits on CO_2 emissions continues to grow in Congress. In 2005, the Senate (with bipartisan support) passed a resolution finding that accumulating global warming emissions are causing temperatures to rise beyond natural variability and posing a "substantial risk" of rising sea levels and more frequent and severe droughts and floods. It states that "mandatory steps will be required to slow or stop the growth" of global warming emissions and that "Congress should enact a

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[64] California Air Resources Board, "Climate Change Emission Control Regulations." Online at *http://www.arb.ca.gov/cc/factsheets/cc_newfs.pdf*.

[65] See the California Clean Cars Campaign website (*http://www.calcleancars.org/news.html#senators*).

[66] Minnesota also has a renewable energy requirement for one utility, Xcel Energy (see *http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=47*). Also see Ryan H. Wiser, "Meeting Expectations: A Review of State Experience with RPS Policies," Lawrence Berkeley National Laboratory, March 2006. Online at *http://eetd.lbl.gov/ea/ems/reports/awea-rps.pdf*.

[67] Massachusetts Department of Environmental Protection, "Emissions Standards for Power Plants," 310 CMR 7.29; New Hampshire Revised Statutes Annotated. "Multiple Pollutant Reduction Program," Chapter 125-O; Washington Revised Code, "Carbon Dioxide Mitigation," Chapter 80.70; Oregon Revised Statutes, Carbon Dioxide Emissions Standard, § 469.503.

[68] West Coast Governors' Global Warming Initiative. Online at *http://www.ef.org/westcoastclimate*.

[69] US Mayors Climate Protection Agreement. Online at *http://www.seattle.gov/mayor/climate/*.

[70] Cities for Climate Protection. Online at *http://www.iclei.org/index.php?id=1118*.

comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases." The program goal would be to eventually reverse the growth of such emissions in a way that would not harm the U.S. economy and would encourage comparable action by major trading partners.[71] In May 2006, an identically phrased resolution was adopted with bipartisan support by the powerful House Appropriations Committee.[72]

It is widely understood that by using the phrase "mandatory, market-based limits," the Senate was referring to a particular kind of regulatory approach known as cap-and-trade. Under such a program, a cap would be established limiting how many tons of CO_2 could be emitted nationwide, and the same number of "allowances" would be issued, each one granting its owner the right to emit one ton of CO_2.

A market price for CO_2 allowances would emerge as operators begin buying and selling them. In practice, power plants that could reduce CO_2 emissions at a lower cost than the market price of an allowance would do so; those that could not would purchase additional allowances to cover their emissions. This system of regulation was pioneered in 1990 to reduce power plants' emissions of sulfur dioxide and other pollutants that cause acid rain, and it proved so successful and efficient that virtually every proposal to regulate CO_2—whether international, regional, or federal—has included some form of cap-and-trade.[73]

As of July 2006, there are at least seven proposals[74] under consideration that would establish a cap-and-trade system for CO_2, including the Climate Stewardship and Innovation Act (S. 1151) introduced by Senators John McCain (R-AZ) and Joseph Lieberman (D-CT) and a proposal sponsored by Senator Jeff Bingaman (D-NM) modeled after a proposal of the National Commission on Energy Policy (NCEP).[75] The Senate Energy and Natural Resources Committee also conducted extensive hearings on the design features of a cap-and-trade system based on the NCEP model in April 2006, accepting comments from many different stakeholders. Many members of the power industry participated in these hearings, including companies that support mandatory regulations and those that, while still opposed to mandatory limits, now consider them inevitable and want to have a say in shaping them (see part III). Two of the most

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[71] Sense of the Senate on Climate Change, H.R.6 §1612, Energy Policy Act of 2005. This resolution passed by a vote of 54-43.

[72] See Senate Committee on Energy and Natural Resources, "Chairman Domenici and Senator Bingaman React to House Committee Vote on Climate Change," press release, May 10, 2006. Online at *http://energy.senate.gov/public/index.cfm?FuseAction=About.Subcommittee&Subcommittee_ID=7*.

[73] Another regulatory option, though one with much less political momentum, is enactment of a carbon tax. By setting a price on CO_2 emissions, the effect on coal plant risks would be the same as a cap-and-trade system that results in equivalent allowance prices, and the arguments in this paper would still apply.

[74] In addition to those mentioned in the text, these proposals include the Clean Air Planning Act of 2006 (S. 2724) introduced by Senator Thomas Carper (D-DE); the Keep America Competitive Global Warming Policy Act of 2006 (H.R. 5049), introduced by Representatives Tom Udall (D-NM) and Tom Petri (R-WI); and the Strong Economy and Climate Protection Act, announced and circulated for discussion by Senator Dianne Feinstein (D-CA) but not yet introduced.

[75] The NCEP proposal is set forth in "Ending the Energy Stalemate" (online at *http://www.energycommission.org/site/page.php?report=13*).

ambitious bills -- the Global Warming Pollution Reduction Act (S. 3698) introduced by Senator Jim Jeffords (I-VT) and the Safe Climate Act (H.R. 5642) introduced by Representatives Henry Waxman (D-CA) and Maurice Hinchey (D-NY)-- would aim to reduce heat-trapping emissions 80 percent below 1990 levels (in line with scientific estimates of what is needed to avoid dangerous global warming).[76]

Political support for a cap-and-trade system is extremely broad, encompassing major U.S. environmental advocacy groups and those in industry that support CO_2 regulation in general. This method of regulation has even been explicitly endorsed by a substantial segment of the U.S. evangelical Christian movement. Several dozen evangelical leaders recently issued a statement declaring that the need for action on global warming is urgent and calling for national legislation requiring CO_2 reductions through "cost-effective, market-based mechanisms such as a cap-and-trade program." They stress that we need urgent action because we are making long-term decisions today that will determine CO_2 emissions in the future, including "whether to build more coal-burning power plants that last for 50 years rather than investing more in energy efficiency and renewable energy."[77]

Utilities may be ignoring these political developments under the reckless assumption that any plant built before a cap-and-trade system is adopted will be allocated allowances for free. This gamble ignores the growing opposition to granting such a windfall to utilities (and particularly those who could avoid new allowance costs by simply investing in alternatives to coal).

The RGGI model rule, for example, requires that at least 25 percent of allowances be auctioned rather than allocated, and Vermont, the first Northeast state to pass enabling legislation, requires auctioning 100 percent of allowances.[78] In fact, 28 different stakeholders in the RGGI model rule draft, including businesses, consumer groups, environmental organizations, state agencies, and an electricity distribution company, supported auctioning 50 to 100 percent of allowances.[79] The proceeds from such an auction would be used to fund investments in energy efficiency, renewable energy, and other low-carbon energy technologies, as well as direct rebates to consumers.

On the federal level, Senators Bingaman and Pete Domenici (R-NM) issued a white paper describing the design elements of a mandatory system to reduce CO_2 emissions. The paper notes that auctioning off all allowances would minimize the costs to the U.S. economy as a whole, streamline the administrative process, and avoid unintended competitive advantages and windfall profits for certain market participants.[80]

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[76] See Senator Jeffords' website (*http://jeffords.senate.gov/~jeffords/press/06/07/072006climatebill.html*) and Representative Waxman's website (*http://www.house.gov/waxman/safeclimate/index.htm*).
[77] Evangelical Climate Initiative, "Climate Change: An Evangelical Call to Action." Online at *http://www.christiansandclimate.org/statement*.
[78] RGGI Model Rule. A bill pending in Massachusetts would begin with 50 percent auctioning and increase 10 percent a year (reaching 100 percent auctioning in year six). New York Attorney General Eliot Spitzer is calling for 100 percent auctioning. For more information, see *http://massclimateaction.org/RGGI.htm*.
[79] Environment Northeast, Natural Resources Defense Council, and Pace Law School Energy Project, 2006.
[80] Domenici and Bingaman, 2006.

A recent Wall Street study further predicts that the United States will have an auction-based rather than allocation-based cap-and-trade system.[81]

In short, not only is it now virtually inevitable that a federal program limiting CO_2 emissions will be approved in the next few years, but it is also fairly certain that this program will take the form of a cap-and-trade system under which every ton of CO_2 emitted will come with a cost, determined by the forces of supply and demand for CO_2 allowances.

D. Coal plants will certainly be covered by future climate regulations.

While the scope of a federal program limiting global warming emissions is under active discussion, every climate bill that has been proposed would cover CO_2 emissions from coal plants—for good reason. Coal plants are by far the largest individual sources of CO_2 emissions, representing nearly one-third of U.S. energy-related CO_2 emissions (the entire power sector accounts for 39 percent of such emissions). Coal plants emit about the same amount of CO_2 as all petroleum-based emissions from cars, trucks, trains, and planes combined, which represent another third of U.S. energy-related CO_2 emissions. The remaining third comes from a variety of technologies and sources including, most notably: industrial use of petroleum, natural gas, and coal; residential use of natural gas; and the electricity sector's use of natural gas.[82]

Not only are coal plants a dominant source of CO_2, but they are also relatively few in number compared with the millions of sources in other sectors, making them far easier for any federal program to regulate. A single new 500 MW conventional coal plant, for example, can emit the annual CO_2 equivalent of more than 600,000 cars.[83] All of the federal regulatory proposals described above would limit CO_2 emissions from coal plants; the only question is whether they would also attempt to regulate other sectors of the economy as well.

Additionally, analysis by the U.S. Energy Information Administration (EIA) shows that the electricity sector accounts for many of the most cost-effective reduction options.[84] While power plants account for 39 percent of U.S. energy-related CO_2 emissions, they have the potential to account for somewhere between 66 and 85 percent

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[81] Wynne, 2006.
[82] EPA, 2006; EIA, 2005. Energy-related emissions of CO_2 represent 97 percent of total U.S. emissions of CO_2.
[83] According to the EPA, annual vehicle emissions are about 13,500 lbs/vehicle; see the EPA Personal Greenhouse Gas Calculator (*http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterToolsGHGCalculator.html*). Power plant CO_2 emissions of 4.1 million tons for a new 500 MW plant are based on the Public Service Commission of Wisconsin's Final Environmental Impact Statement for Weston Unit 4 Power Plant, Volume 1, July 2004, 145 (online at *http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf*).
[84] EIA, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals," March 2006. Online at *http://www.eia.doe.gov/oiaf/servicerpt/agg/pdf/sroiaf(2006)01.pdf*.

of energy-related CO_2 emission reductions according to computer models designed to show the least expensive options for complying with various CO_2 regulations.[85]

The most significant change from the EIA's "business-as-usual" scenario to its carbon reduction scenarios is the resulting impact on coal generation. In the business-as-usual scenario, approximately 174 gigawatts (GW) of new coal capacity (the equivalent of 290 new 600 MW coal plants) are added by 2030. By contrast, in the two deepest carbon reduction scenarios EIA analyzed, *not a single new conventional coal plant is added beyond those already under construction*.[86] In other words, the construction of any additional conventional coal plants would make it more expensive to achieve the carbon reduction targets.[87]

III. The power industry increasingly supports federal CO_2 limits.

Over the years, most of the power industry has been strongly opposed to federal CO_2 limits from power plants, but that attitude has been changing rapidly, especially in 2006. Many prominent power companies now openly support the federal regulation of CO_2 from coal plants. The chief executive of Duke Energy, one of the nation's largest coal-burning utilities, has said of global climate change, "From a personal perspective I can think of no more pressing global issue." He went on to say:

> *"From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be—which actions will be penalized and which will be rewarded—we will be unable to take the significant actions the issue requires."*[88]

Duke's website states, "Congress needs to establish a national, economy-wide greenhouse gas mandatory program as soon as possible."[89]

The head of Exelon has stated, "We accept that the science on global warming is overwhelming. There should be mandatory carbon constraints."[90] And the head of PNM

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[85] Ibid., 18.
[86] Ibid., 22. In the deepest carbon reduction scenario, approximately 103 GW of existing coal capacity (171 plants) is retired, and 17 GW of new integrated-gasification combined-cycle (IGCC) capacity with carbon capture and sequestration equipment is added.
[87] UCS does not consider all of EIA's assumptions and methods realistic, nor do we believe its scenarios achieve the lowest possible cost. EIA has typically underestimated the potential of energy efficiency, combined heat and power, and renewable energy to reduce emissions at lower costs (see UCS, *Clean Energy Blueprint*, 2001). However, EIA's modeling is still useful for demonstrating how changes in one variable (e.g., imposition of carbon reduction targets) affect the economics of another (e.g., building new conventional coal plants) under a consistent set of assumptions.
[88] Paul Anderson, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," speech to CERES Annual Conference, April 6, 2006. Online at *http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf*).
[89] "Climate Change: Duke Energy Position on U.S. Climate Change Policy." Online at *http://www.duke-energy.com/environment/policies/climate_change*.

Resources said at Senate hearings, "We believe now is the time for a healthy debate at the federal level on climate change, and we support the move to a mandatory program."[91]

Many other power companies have expressed their support for federal CO_2 limits through coalition statements. In 2003, for example, Calpine, Con Edison, Keyspan, Northeast Utilities, PG&E Corporation, PPL Corporation, Public Service Enterprise Group, and Wisconsin Energy signed onto the CERES Consensus Statement, which called on the federal government to "develop a national, mandatory, market-based program" limiting global warming emissions.[92] In April 2006, the Clean Energy Group's Clean Air Policy Initiative submitted comments to the Senate Committee on Energy and Natural Resources supporting the adoption of a cap-and-trade program for the electricity sector.[93] Entergy, Exelon, and Florida Power & Light thereby added their names to those publicly calling for such a law.[94]

In sum, five of the nation's 10 largest private power producers (Calpine, Duke, Entergy, Exelon, and Florida Power & Light), accounting for more than 15 percent of U.S. electricity generation,[95] now support mandatory limits on CO_2 from power plants. Another (Progress) acknowledged in a 2006 special report to shareholders that the evidence for climate change is sufficient to warrant "action" by the "public sector," which the company believes should cover all sectors of the economy.[96] Executives from three of the remaining companies in the top 10 (American Electric Power, Southern Company, and Xcel), accounting for another 12 percent of U.S. power generation, have acknowledged that federal limits on CO_2 are coming, even if they do not support them.[97]

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[90] John W. Rowe, August 16, 2004, quoted in *Business Week*. Online at http://www.businessweek.com/print/magazine/content/04_33/b3896001_mz001.htm?gl.

[91] Jeff Sterba, April 4, 2006, quoted in the *Albuquerque Tribune*. Online at http://www.abqtrib.com/albq/nw_national_government/article/0,2564,ALBQ_19861_4594645,00.html.

[92] CERES, "Electric Power, Investors and Climate Change: A Call to Action," September 2003. Online at http://www.ceres.org/pub/docs/Ceres_electric_power_calltoaction_0603.pdf.

[93] Michael J. Bradley, April 4, 2006. Online at http://energy.senate.gov/public/_files/ExecutiveSummariesforwebsite.pdf.

[94] In addition, three signatories of the CERES Consensus Statement (Calpine, PG&E, and Public Service Enterprise Group) are part of the Clean Energy Group Clean Air Policy Initiative.

[95] The nation's 10 largest private power producers in 2004, in order of megawatt hours produced, were American Electric Power, Southern Company, Exelon, FPL Group, Entergy, Dominion, Duke Energy, Progress Energy, Calpine, and Xcel Energy. (Duke Energy has since moved up in the rankings by merging with Cinergy). See CERES, NRDC, and PSEG, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States—2004," April 2006. Online at http://www.nrdc.org/air/pollution/benchmarking/default.asp.

[96] Progress's vague statement on the need for action on global warming has been interpreted by the trade press as a call for carbon regulation. See "Progress Energy calls for US carbon regulation," March 31, 2006, *Carbon Finance Online* (online at www.carbonfinanceonline.com; subscription required); also see "2006: Progress Energy's Report to Shareholders: An Assessment of Global Climate Change and Air Quality Risks and Actions" (online at http://www.progress-energy.com/environment/climatechange.asp).

[97] See Dale E. Heydlauff (American Electric Power), quoted in "Global Warming," August 16, 2004, *Business Week* (online at http://www.businessweek.com/print/magazine/content/04_33/b3896001_mz001.htm?gl); David Ratcliffe (Southern Company), quoted in "U.S. Utilities Urge Congress to Establish CO_2 Limits," Bloomberg.com (online at http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us); and

This expectation is widely shared in the industry: a 2004 national survey of electricity generating companies found that 60 percent of respondents expected mandatory limits on CO_2 within 10 years, and about half expected such limits within five years.[98]

The industry leaders quoted above echo the rising call for CO_2 limits by companies in other industries, including some of the nation's largest corporations. Wal-Mart calls climate change "an urgent threat not only to our business but also to our customers, communities, and the life support systems that sustain our world."[99] Both Wal-Mart and GE expressed support for CO_2 limits in April 2006 Senate hearings,[100] and Ford Motor Company and Hewlett-Packard joined 22 other multinational corporations in a 2005 statement urging leaders of the G8 nations to adopt cap-and-trade or other market-based mechanisms to limit global warming emissions.[101]

When a significant share of industry speaks out in favor of environmental regulations, including several major companies in the industry sector likely to be most heavily regulated, it is a strong sign that such regulations are near at hand. It is quite possible that CO_2 limits will be in place and operational before the same could be said for a proposed coal plant currently in the regulatory approval process.

IV. The private financial community is pushing companies to disclose and reduce their exposure to future climate regulation.

Concern is undeniably growing among investors and lenders over the financial risks of future CO_2 constraints. For example, the Investor Network on Climate Risk (INCR) was launched in 2003 as a coalition of institutional investors managing $600 billion in assets; by early 2006, it included a much wider array of investors managing more than three trillion dollars in assets.[102] The Carbon Disclosure Project, an investor coalition undertaken on the international level to obtain global warming emission data from 1,900 multinational corporations, now represents investors managing $31 trillion in assets—three times more than in 2003.[103]

The INCR stresses the regulatory risk faced by U.S. companies with high global warming emissions, calling federal carbon constraints "only a matter of time."[104] It has

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Wayne Brunetti (Xcel), quoted in "Xcel Energy expects US carbon regulations," September 9, 2004, PointCarbon (online at http://www.pointcarbon.com/article.php?articleID=4459&categoryID=147).

[98] PA Consulting Group, "PA survey finds that US generating companies expect mandatory carbon dioxide regulations within 10 years," press release, October 22, 2004. Online at http://www.paconsulting.com/news/press_release/2004/pr_carbon_dioxide_regulations.htm.

[99] Wal-Mart website (http://walmartstores.com/GlobalWMStoresWeb/navigate.do?catg=347).

[100] Raymond Bracy (Wal-Mart) and David Slump (GE Energy), comments to Senate Energy and Natural Resources Committee, April 4, 2006. Online at http://energy.senate.gov/public/_files/ExecutiveSummariesforwebsite.pdf.

[101] "Statement of the G8 Climate Change Roundtable," World Economic Forum, June 9, 2005. Online at http://www.weforum.org/pdf/g8_climatechange.pdf.

[102] Investor Network on Climate Risk (INCR) website (http://www.incr.com/index.php?page=2).

[103] Carbon Disclosure Project website (http://www.cdproject.net/aboutus.asp).

[104] INCR website, "INCR Overview." Online at http://www.incr.com/index.php?page=9.

called on companies in the electricity sector to estimate how future heat-trapping emission limits will affect their businesses and to identify steps they are taking to reduce those effects.[105] In doing so, a board member of the nation's largest public pension fund said, "Ignoring the impact of carbon on the environment and on corporate bottom lines would be fiscally irresponsible and a disservice to investors, taxpayers and the environment."[106]

Investors are particularly concerned with the financial wisdom of building new coal plants in the United States given the growing momentum here for federal CO_2 limits. Several of the nation's largest institutional investors recently warned TXU that the "future cost of carbon could alter the prudence" of the utility's plan to invest in new coal plants, and that TXU was "potentially exposing itself to unprecedented compliance costs" given the long lifespan of coal plants. It urged TXU to disclose to shareholders "how it has accounted for the 'future cost of carbon' in its resource planning for these plants."[107]

Many of the nation's largest banks and investment firms have recently announced more aggressive climate policies. Bank of America, for example, has launched a formal effort to assess and limit its risk from financing emission-intensive industries, including a commitment to reduce emissions from its public energy and utility portfolio seven percent by 2008.[108] JP Morgan Chase sees climate change as a "critical issue" with "potentially very serious consequences for both ourselves as well as our clients." In a recent speech, its director of environmental affairs said, "for the new power projects we are beginning to quantify the financial costs of those greenhouse gas emissions and incorporating that into our financial analysis of the transaction," and went on to note that looking at those costs is "going to have a big impact."[109] The head of global projects for Lehman Brothers has also addressed a cap on global warming emissions by saying, "There's a consensus that something's coming," adding that, "people are very much focused on how that's going to affect economics."[110]

Wall Street is also beginning to assess the impact new laws would have on particular power companies. Bernstein Research recently released a report describing the growing momentum toward CO_2 regulation, concluding that, "Regardless of which party wins the 2008 presidential elections . . . it is probable that the next administration will favor mandatory national limits on CO_2 emissions."[111] The report went on to identify the

[105] INCR website, "Ten Point Investor Action Plan." Online at *http://www.incr.com/index.php?page=20*.
[106] Phil Angelides, quoted in "Investors Call on Power Sector and Wall Street to Focus Attention on Financial Risks From Climate Change," CERES website, April 13, 2005. Online at *http://www.ceres.org/news/news_item.php?nid=108*.
[107] INCR website, "Investors Concerned About TXU's Aggressive Coal Strategy," May 16, 2006. Online at *http://www.incr.com/index.php?page=ia&nid=178*.
[108] Bank of America website, "Bank of America Climate Change Position." Online at *http://www.bankofamerica.com/newsroom/presskits/view.cfm?page=climateandforests*.
[109] Amy Davidson, "Financial Institutions: Challenges and Opportunities," speech to the Earth Institute, Columbia University, March 29, 2006. Online at *http://www.earthinstitute.columbia.edu/sop2006/transcripts/tr_davidsen.html*.
[110] John Veech, quoted in "Analysts View Energy Policy Act through Climate Change Lens," August 30, 2005, *SNL Generation Markets Week*.
[111] Wynne, 2006.

utilities facing the greatest financial risk: "unregulated coal-fired generators supplying markets where gas is the predominant price setting fuel,"[112] which cannot pass the added costs of an emission cap on to consumers. The assumption, of course, is that regulated utilities *will* be able to pass future compliance costs on to ratepayers—an assumption we challenge below (see part VI), but which does reflect current regulatory practice.

This attitude reveals why, at least for the moment, some sectors of the financial community are still willing to help regulated utilities build new coal plants even when they know that such plants will be substantially more expensive in the carbon-constrained world ahead. Wall Street is not concerned with protecting ratepayers—that will be a job for state regulators.

V. Future costs of CO_2 regulation must be part of any realistic estimate of a new coal plant's operating costs.

A. CO_2 costs are increasingly factored into risk planning by utilities, regulators, and regional planners.

Representatives of three utilities explained in a 2005 trade journal article the importance of assessing and managing CO_2 risk:

> *"The financial risk associated with likely future regulation of carbon dioxide emissions is becoming a focus of utilities' and regulators' risk management efforts, as they recognize the imprudence of assuming that carbon dioxide emissions will not cost anything over the 30-year or longer lifetime of new investments. Utilities can help protect their customers and shareholders from this financial risk by integrating an estimated cost of carbon dioxide emissions into their evaluation of resource options, and selecting the overall least-cost portfolio of resources. Utilities can learn from the experience that some utilities have gained at managing this risk to ensure that today's investments do not lock customers or shareholders into much higher costs tomorrow if greenhouse gases are regulated."*[113]

A recent Lawrence Berkeley National Laboratory analysis of western U.S. utilities' resource planning practices found the practice of quantifying CO_2 risk to be widespread: "Given the potential for future carbon regulations to dominate environmental compliance costs, seven of the twelve utilities in our sample . . . specifically analyzed the risk of future carbon regulations on portfolio selection."[114] State regulators have since ordered three additional utilities to include CO_2 costs in their planning, leaving only two

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[112] Ibid, 2.

[113] Karl Bokenkamp (Idaho Power), Hal LaFlash (Pacific Gas & Electric), Virinder Singh (Pacificorp), and Devra Bachrach Wang, "Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions," July 2005, *The Electricity Journal* 18(6): 11–24.

[114] Mark Bolinger and Ryan Wiser, "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans," Lawrence Berkeley National Laboratory, August 2005. Online at http://eetd.lbl.gov/ea/EMS/reports/58450.pdf.

utilities (out of the 12 sampled) that continue to ignore CO_2 risks.[115] In its most recent resource plan, Northwestern Energy (formerly Montana Power) says it is "the mainstream practice of utility planners to factor a carbon tax into their models."[116]

California, Oregon, and Washington require utilities to factor CO_2 costs into their resource plans, and Montana ordered one utility, Northwestern Energy, to do so in its 2005 plan.[117] The California PUC actually chose a specific CO_2 value and requires the three investor-owned utilities in the state to use that value when evaluating bids (which has a direct, ongoing effect on resource selection outside the planning context).[118]

In 2005, the Northwest Power and Conservation Council (often referred to as the Northwest Council) issued a resource plan that incorporates estimates of future CO_2 values beginning in 2008.[119] This is worth noting not only because the 20-year plans developed by this federally created regional agency cover the entire Northwest, but also because most energy planning is conducted by utilities rather than independent planners who have no financial incentive to select one type of resource over another.

B. A useful range of CO_2 price forecasts is emerging from the literature.

Over the last few years, federal cap-and-trade proposals before Congress have spawned numerous analyses using computer models to simulate the market response to these regulations. For example, the EIA, the U.S. Environmental Protection Agency, the Massachusetts Institute of Technology (MIT), and the Tellus Institute have all modeled the effects of proposed legislation resulting in varying CO_2 cost projections.[120] The

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[115] Ibid., 62.

[116] Northwestern Energy, "2005 Electric Default Supply Resource Procurement Plan," Volume 2, Chapter 1, 25.

[117] See Bolinger and Wiser, 2005, 57 (note 75) and 60; Washington Administrative Code, section 480-100-238; and California PUC, "Interim Opinion on E3 Avoided Cost Methodology," April 22, 2004 (online at http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/45195.htm#TopOfPage).

[118] California PUC, "Interim Opinion on E3 Avoided Cost Methodology," Decision 05-04-024, Proceeding 04-04-025, 29 and 89. Online at http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/45195.htm. Also see UCS testimony submitted in this proceeding (online at http://www.ucsusa.org/clean_energy/clean_energy_policies/testimony-on-accounting-for-californias-global-warming-gas-costs.html).

[119] Northwest Power and Conservation Council, "The Fifth Northwest Electric Power and Conservation Plan," 2005, Volume 1, 19. Online at http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.

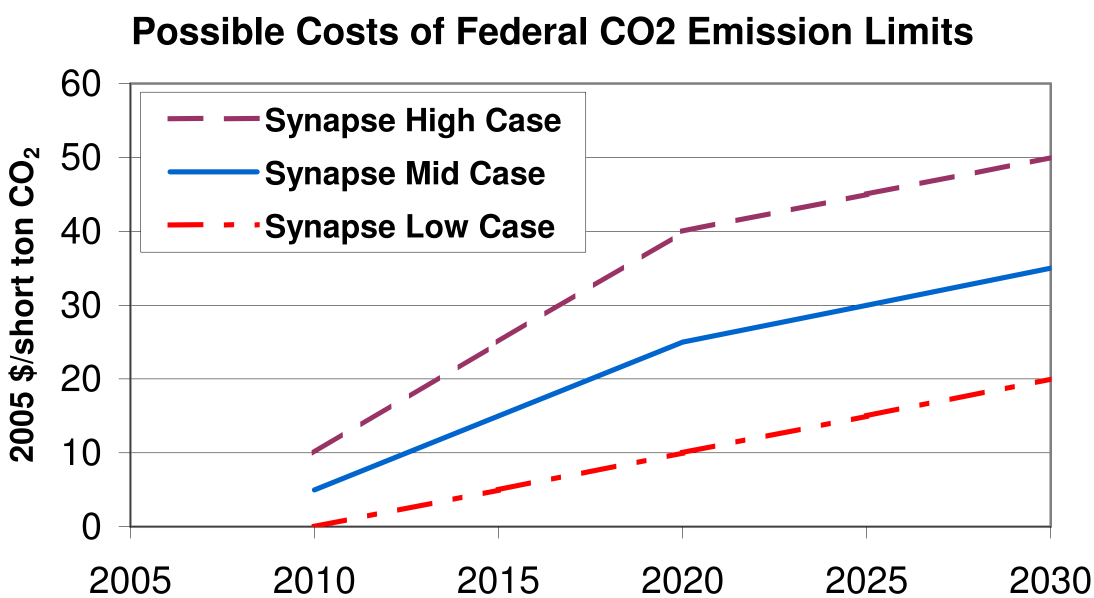
[120] See EIA, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Targets," March 2006; "Impacts of Modeled Recommendations of the National Commission on Energy Policy," April 2005; "Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003," May 2004; "Analysis of S.139, the Climate Stewardship Act of 2003," June 2003;(online at http://www.eia.doe.gov/oiaf/service_rpts.htm); EPA, "Multi-Pollutant Legislative Analysis: The Clean Power Act," October 2005; and "Multi-Pollutant Legislative Analysis: The Clean Air Planning Act," October 2005 (online at http://www.epa.gov/airmarkets/mp/index.html); Massachusetts Institute of Technology Joint Program on the Science and Policy of Global Change, "Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal," June 2003 (online at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt97.pdf); Tellus Institute, "Analysis of the Climate Stewardship Act Amendment," June 2004 (online at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf).

domestic policy option that has been subjected to the most analysis is the Climate Stewardship Act proposed by Senators McCain and Lieberman.

Another more recent policy proposal analyzed by the EIA is one developed by the NCEP. This approach focuses on reducing emission "intensity" (emissions per dollar of gross domestic product) rather than total emissions, but like all cap-and-trade proposals it would still impose a cost on CO_2 emissions.

In May 2006, Synapse Energy Economics conducted a review of the cost projections of 10 such modeled analyses, as well as the emerging policy response to climate change and recent scientific and political developments.[121] This review resulted in the high, mid-range, and low CO_2 cost projections shown in Figure 4.

Figure 4



Source: Johnston et al., 2006. [122]

While Synapse warns that the real cost of CO_2 is unlikely to follow a smooth path, the company believes its projections "represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation."[123] When

[121] Lucy Johnston, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Roschelle, and David White, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," Synapse Energy Economics, May 18, 2006. Online at *http://www.synapse-energy.com*.
[122] Ibid., p. 40.
[123] Ibid., 39.

Synapse's cost projections are levelized[124] over 30 years to 2005 dollars, the low CO_2 cost projection is \$8.50/ton, the mid-range projection is \$19.60/ton, and the high projection is \$30.80/ton.[125]

Estimates of the price of future CO_2 allowances vary depending on a variety of factors, including the emission reduction target, the availability of offsets, whether international trading is allowed, the implementation timeline, and the existence of complementary policies such as energy efficiency programs and renewable electricity standards.[126] Two assumptions are particularly important and merit additional discussion here: the emission reduction target and the rate of technological progress.

First, all the analyses are based on relatively modest changes in U.S. emissions. The Climate Stewardship Act, for example, aims to return U.S. CO_2 emissions to 2000 levels over the period 2010 to 2015.[127] The NCEP proposal, which has been at the forefront of Senate hearings to design a cap-and-trade system, would slow the rate of emission growth but not reverse it.[128] None of the federal proposals that underlie these CO_2 cost estimates actually claim to deliver emission cuts sufficient to stabilize global CO_2 concentrations at a level that would avoid dangerous climate change.[129] Even the Kyoto Protocol, which would have required the United States to cut emissions seven percent below 1990 levels by the period 2008 to 2012, is only intended to be a first step leading to greater reductions later.[130]

As discussed in part I, section C, the science indicates that in order to prevent dangerous climate change, developed nations will need to reduce CO_2 emissions as much as 60 to 80 percent by 2050. Therefore, whatever federal policy to limit CO_2 emissions is initially adopted will have to be quickly followed with increasingly tighter caps if we are to put ourselves on a path toward climate stabilization in the decades ahead.

Much tighter national caps than those that have been analyzed would—all other things being equal—have the effect of driving CO_2 prices higher than the studies project. However, at some point, rising CO_2 prices would make low- or zero-carbon technologies competitive, leveling out the increase in CO_2 costs. How quickly that point is reached depends on a second important assumption**:** how quickly these technologies will develop. Most of the studies that provide the basis for the published cost projections (particularly

[124] "Levelized" cost means "The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation)." EIA Glossary, *http://www.eia.doe.gov/glossary/glossary_l.htm*.
[125] Johnston, et al., 2006,, 41.
[126] Ibid, 35–39.
[127] See Pew Center on Global Climate Change, "Summary of the 2003 Climate Stewardship Act." Online at *http://www.pewclimate.org/policy_center/analyses/s_139_summary.cfm*.
[128] Johnston et al., 2006, Figure 5.1.
[129] The newly introduced bills discussed in part II.C aiming for 80 percent reductions below 1990 levels by 2050 have not yet been the subject of analysis and are not reflected in cost projections.
[130] Climate Change Secretariat, "Caring for Climate: A Guide to the Climate Change Convention and the Kyoto Protocol," United Nations Framework Convention on Climate Change, 2003, 25. Online at *http://unfccc.int/resource/cfc_guide.pdf*.

those by the EIA) make very pessimistic assumptions about the cost and performance of renewables, efficiency, and other alternative technologies, both today and in the years ahead.[131] Moreover, they assume that there will be no new policies requiring or providing incentives for greater use of these technologies, despite growing support for such policies at both the state and federal level.

Using more optimistic assumptions about the costs, performance, and policy support for these clean energy technologies would have the effect of reducing CO_2 prices below projected levels (or keeping them from rising as much as they otherwise would in response to ever-tightening caps).[132] In this way, the rapid development of coal alternatives would have the paradoxical effect of reducing the future costs of coal power. Of course, if utilities and regulators use these more optimistic assumptions about the development of low-carbon energy in forecasting CO_2 prices, they must use the same assumptions when determining whether it would be cheaper in the long run to simply invest in low-carbon alternatives rather than building new coal plants. Optimism about alternative technologies to coal may reduce the estimated cost of coal plants by keeping future CO_2 allowance prices low, but that same optimism undermines the economic logic of building a new coal plant in the first place.

The CO_2 price projections by Synapse are roughly consistent with the range of projections being used by utilities and the Northwest Council in their resource plans, though without encompassing the highest and lowest of those values. Table 1 shows the range of numbers in use.[133] (In some cases, these values are discounted by the utility with a probability weighting when actually used in planning.)

Table 1: CO_2 Emission Trading Assumptions for Various Years (in 2005 dollars)

PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

Source: Johnston et al., 2006, Table 6.1.

131 For example, see Steve Clemmer (Union of Concerned Scientists), "Renewable Energy Modeling Issues in the National Energy Modeling System," presentation at the National Renewable Energy Laboratory Energy Analysis Seminar, Washington, DC, December 9, 2004. Online at *http://www.nrel.gov/analysis/seminar/docs/2004/ea_seminar_december_9.ppt*.

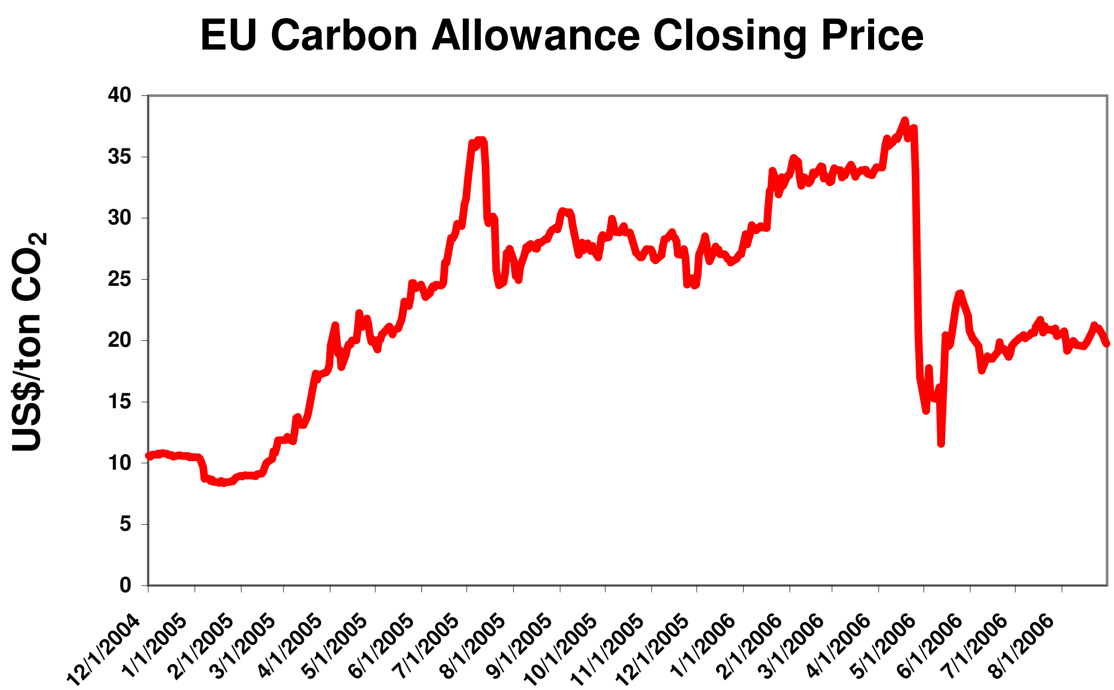
132 The studies reviewed by the Tellus Institute used more optimistic assumptions and included complementary policies for energy efficiency and renewable energy technologies. The resulting CO_2 cost projections were closer to the Synapse mid-range projections and leveled off more in the later years of the forecast. See Tellus Institute, 2004.

133 Ibid., 30.

Not included in Table 1 is the estimate of future CO_2 regulatory costs that California requires its utilities to assume in resource selection. At eight dollars per ton in 2004, rising by only five percent annually (less than the rate at which Synapse's projections rise), California's estimate begins near the high end of the Synapse analysis but move toward the low end in later years.[134]

Wall Street analysts Bernstein Research recently modeled the impact of a CO_2 allowance requirement on the earnings of several U.S. coal-fired generators, choosing nine dollars per ton of CO_2 as the price on which to base its analysis. It also considered a \$28/ton CO_2 price based on the allowance prices recently prevalent under the European Union's cap-and-trade system, which reached levels as high as \$35/ton during the past year.[135] As Figure 5 shows, CO_2 prices dropped sharply in May on news that many companies emitted less CO_2 than expected, suggesting that large emitters had been allocated too many allowances.[136] Prices have since partially rebounded.

Figure 5



Source: EU: PointCarbon.com using an average exchange rate for 2005 of 1.25 U.S. dollars per euro.

There are great uncertainties associated with predicting the future cost of CO_2 allowances, but this holds true for many other aspects of utility planning—especially

[134] See Bolinger and Wiser, 2005, 60.
[135] Wynne, 2006, 11–17.
[136] Reuters, "EU undershoots emissions cap that critics call lax," May 12, 2006. Online at *http://today.reuters.com/News/CrisesArticle.aspx?storyId=L12101022*.

when considering the wisdom of investing in capital-intensive power plants that typically operate for a half-century or more in a rapidly changing world. The most prudent way to assess and minimize this risk is to consider the impact of a reasonable range of CO_2 cost projections (such as those described above) on a proposed coal plant. The one CO_2 price projection certain to be wrong is zero.

C. Reasonable projections of CO_2 prices would greatly increase the cost of coal power.

CO_2 allowance prices in the ranges discussed above would significantly increase the price of power from new coal plants. How much CO_2 allowance prices raise the cost of generating electricity from coal depends on the efficiency of the plant in question, but generally speaking, new coal plants emit roughly one ton of CO_2 per megawatt hour (MWh) of electricity produced.[137] This means, for example, that a CO_2 price of $10 per ton would increase a plant's costs by $10/MWh (or one cent per kilowatt-hour). Figure 6 shows how the cost of coal-fired electricity would rise in response to different CO_2 prices, starting with the EIA's estimated average base price of $47.50/MWh for new pulverized coal plants placed into service in the upper Midwest in 2015.[138]

Applying the Synapse levelized CO_2 cost projections to a coal plant increases the cost of energy from the EIA's average coal plant by the amounts and percentages shown in Table 2. For example, the cost of energy from an average coal plant would be 40 percent higher over its operating lifetime assuming mid-range CO_2 costs starting at five dollars per ton in 2010 and rising to $35 per ton by 2030.

Table 2: Increase in Energy Cost Based on Projected CO_2 Cost

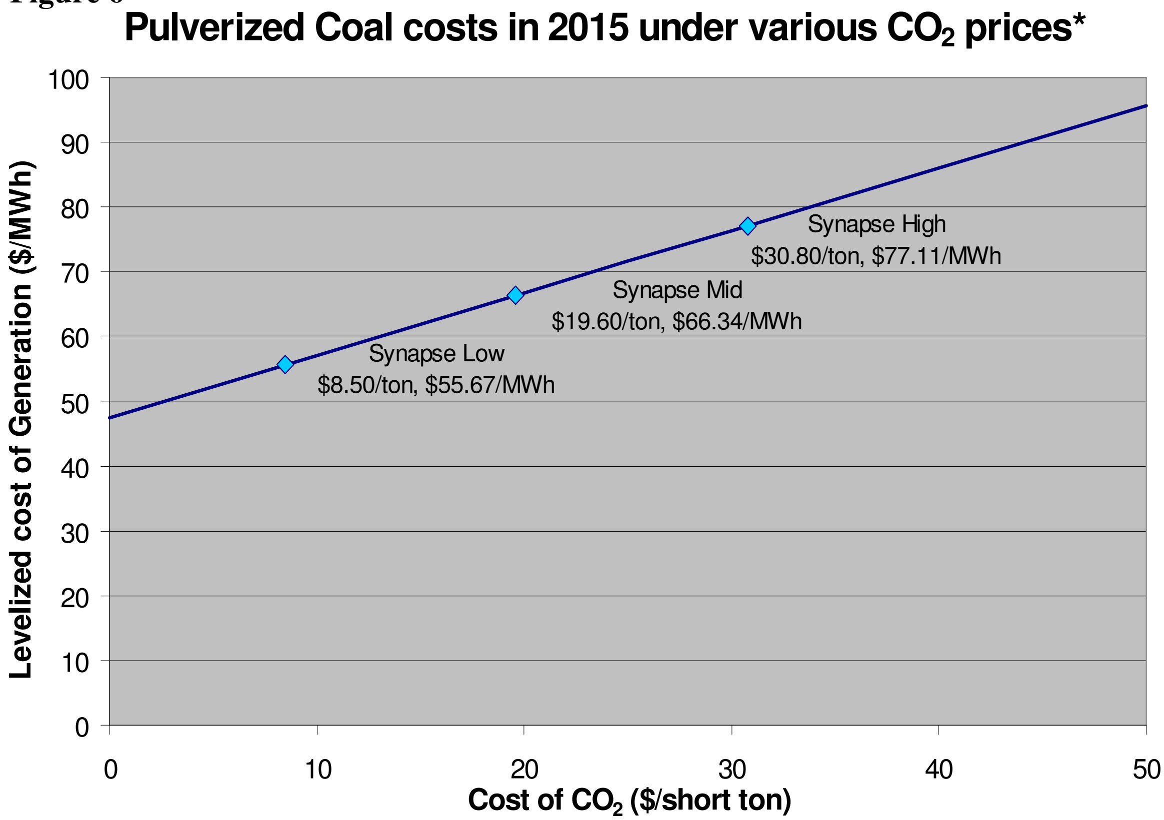
Price of CO_2 Allowance (levelized)	Cost of energy	Percent increase above base price
Base price (no CO_2 cost)	$47.50/MWh	–
Low projection: $8.50/ton	$55.67/MWh	17%
Mid-range projection: $19.60/ton	$66.34/MWh	40%
High projection: $30.80/ton	$77.11/MWh	62%

[137] Coal has a carbon intensity of 220 pounds per million British thermal units (Btu) and a new supercritical pulverized coal plant has a heat rate of 8,742 Btu per kilowatt-hour in 2005 (220 lbs/million Btu x 8,742 Btu/kWh/2,000 lbs/ton x 1,000 kWh/MWh/1,000,000 = 0.96 ton of CO_2 per MWh). See EIA, *Assumptions for Annual Energy Outlook 2006*, 2006.

[138] EIA, "NEMS EMM Factors for AEO06," spreadsheet, 2006. The costs are representative of a new coal plant built in the Midwest. Recent data indicates that EIA's base price for coal may be low. EIA's figure assumes overnight capital costs of $1,235/kW for a new plant. By comparison, the engineering firm Black and Veatch assumes overnight capital costs of $1,730/kW, based on the average cost of over 60 coal plant projects under construction or with air permits. (Source: Personal Communication with Ric O'Connell, Black and Veatch, August 20, 2006.) Using these capital costs, along with EIA's other assumptions, would raise the base cost of energy to $58/MWh.

Any utility proposing to build a coal plant would be reckless to make such a long-term investment without fully assessing a variable that could easily increase costs by $86 million per year on average, or $4.3 billion over a 50-year period, for a 600 MW coal plant.[139] The risk of future carbon constraints is far too great to ignore.

Figure 6



Source: EIA, "NEMS EMM Factors for AEO06," spreadsheet, 2006, and Johnston et al., 2006. The costs are representative of a new coal plant built in the Midwest.

D. Given the carbon-constrained world ahead, renewables and efficiency will generally be a much better investment than new coal plants.

In many cases, coal plants are already more expensive than cleaner options. This is particularly true with respect to investments in energy efficiency and wind turbines (in locations with favorable winds). With mid-range estimates of future CO_2 costs adding close to $20/MWh (or two cents per kilowatt-hour) to the cost of energy from a coal plant, cleaner options will cost less than coal in an even wider range of cases.

[139] Based on an estimate by Synapse for the Big Stone II coal plant under a mid-range CO_2 cost projection. See David A. Schlissel and Anna Sommer, direct testimony to the South Dakota PUC, case no. EL05-022, May 19, 2006, 24. Online at http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/testimonyschlisselsommer.pdf.

While the exact cost comparisons will vary by location, two recent analyses compare coal plants with cleaner options in a carbon-regulated world, and in these analyses new conventional coal plants cannot compete. The first such analysis is a massive exercise in regional resource planning recently conducted by the Northwest Council.[140] With no financial stake in the outcome to skew its planning judgment, the council's fifth 20-year plan (adopted in December 2004) is a useful contribution to resource planning.

Among other things, the plan ranks various supply- and demand-side options on a cents-per-kilowatt-hour scale. The Northwest Council identifies 25 different conservation and renewable options that cost less than the cheapest new coal plant (even in Montana, a coal-producing state).[141] The plan looks at many different scenarios and various price estimates for future CO_2 costs (though these estimates pre-date recent developments such as the Senate resolution calling for carbon regulation).[142]

The plan concludes that much more investment in conservation is warranted even though the Northwest has already made relatively high investments in conservation over the years.[143] Overall, the Northwest Council's approach of identifying options that are both low-cost and low-risk yielded a plan that greatly increases investment in conservation and wind and *does not include any new conventional coal plants* for the region throughout the 20-year planning period.[144] While the council's cost estimates may not directly apply to other regions, they provide a valuable example of how conventional coal plants become uncompetitive compared with energy efficiency and renewable energy when independent resource planners use realistic assumptions about the future and factor in carbon risk.

The second relevant analysis was conducted by Synapse Energy Economics, which in May 2006 submitted testimony critiquing a resource comparison that a coalition of utilities seeking to build a conventional coal plant submitted to South Dakota regulators.[145] The utilities did not compare the proposed 600 MW Big Stone II plant with a comparable investment in energy efficiency, nor did Synapse. However, the utilities did compare Big Stone II with the alternative of building 600 MW of wind power along with a 600 MW natural gas combined-cycle plant. Not surprisingly, the utilities' wind/gas alternative was more expensive than Big Stone II, since it assumed only 600 MW of wind power and unnecessarily assumed that the wind turbines required 100 percent backup from natural gas to compensate for the wind's intermittent nature.

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140 Northwest Power and Conservation Council, 2005.
141 Ibid., Table OV-2, 26–27.
142 Ibid., 19. The Northwest Council assumes CO_2 costs of between zero and $15 per ton beginning in 2008, and between zero and $30 per ton beginning in 2016.
143 Ibid., 4, 29–31.
144 Ibid., 29.
145 David A. Schlissel and Anna Sommer, direct testimony to the South Dakota PUC, case no. EL05-022, May 26, 2006. Online at *http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/testimonyschissel052606.pdf*.

Synapse reworked the comparison by increasing the amount of wind power to 800 and 1200 MW, reducing the amount of natural gas to levels that would be needed to provide an equivalent amount of electric generation and capacity (300 to 480 MW) as the coal plant,[146] and factoring in its low, mid-range, and high CO_2 cost estimates (described in part V, section B). Synapse also completed a sensitivity analysis of a few key variables including the continued existence of the federal production tax credit for wind, a capacity value for wind (which affects the amount of natural gas capacity needed), and whether the utilities were investor-owned or publicly owned.

Under all of the CO_2 price forecasts, the analysis showed that all of the high-wind (1,200 MW) scenarios were approximately the same or less costly than the 600 MW coal plant, even without the federal production tax credit and using a very conservative capacity value for wind. Under the most likely mid-range CO_2 price forecast, Big Stone II cost 27 to 71 percent more than the high-wind scenarios, across the entire range of assumptions.[147]

The analysis also showed that all of the wind/gas alternatives had lower costs than the 600 MW coal plant under both the mid-range and high CO_2 price forecasts. Coal fared remarkably poorly in these comparisons even though Synapse did not correct all of the utilities' assumptions that underestimated the cost of coal and overestimated the cost of wind.[148] In addition, the Big Stone II co-owners recently announced that the capital costs for the project have increased by 50 percent—from $1.2 billion to $1.8 billion.[149] Using these new costs, and incorporating energy efficiency into the alternatives analysis, would make the alternatives even more economically viable than described above.

Both the Northwest Council and Synapse analyses show coal unable to compete financially with other options available today when future carbon constraints are considered. In the future, coal is likely to be even less competitive, because policies designed to combat global warming will not just make coal more expensive but will surely accelerate improvements in cleaner technologies. Unlike conventional coal plants, many energy efficiency and renewable energy technologies are still relatively new. As they break out of niche markets and achieve greater economies of scale, improvements in price and performance will follow. Utilities that invest heavily in coal today are therefore

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[146] Ibid., 14. Synapse explains in its testimony that, by accepting the utilities' assumption that any dedicated backup plants would be built to support wind power, its analysis overstates the cost of the wind options.
[147] Ibid., Tables 1 and 2, 17. (A corrected version of these tables with slight alterations to the originally-filed numbers is online at *http://www.state.sd.us/puc/commission/dockets/electric/2005/el05-022/corrected062306.pdf*.)
[148] Ibid., 13–16. Synapse explains in its testimony its decision not to correct several of the utilities' original assumptions that bias the analysis against wind. For example, while the tax and financing advantages of public utilities were reflected in the cost of Big Stone II, they were not reflected in the cost of wind. Synapse corrected the utilities' assumption that wind had zero capacity value, but it conservatively assumed that wind resources have a capacity value of only 15 or 25 percent (despite recent utility studies showing that wind in the region has a capacity value between 27 and 34 percent). Synapse also used the utilities' value of $12/MWh for the production tax credit, despite data from the EIA showing a value of $21/MWh.
[149] Associated Press, "Higher cost for SD power plant won't help ND chances, exec says," August 4, 2006. Online at *http://www.kxma.com/getARticle.asp?ArticleId=30517*.

not only running unnecessary financial risks, but also losing the flexibility to take full advantage of the technological opportunities ahead.

E. Retrofitting a pulverized coal plant to limit CO_2 emissions is feasible, but will be very expensive.

Coal plants emit far more CO_2 than any pollutant that is federally regulated today. By way of example, the Final Environmental Impact Statement for the Weston 4 coal plant in Wisconsin lists potential mercury emissions of 78 pounds per year, sulfur dioxide emissions of about 2,300 tons per year, and nitrogen oxide emissions of about 1,600 tons per year. CO_2 emissions, by comparison, are projected to be 4,100,000 tons per year.[150] Collecting and disposing of CO_2 emissions therefore pose much greater technological challenges than those faced by coal plants to date.

It is considered technologically possible to capture 80 to 90 percent of the CO_2 from a conventional coal plant by scaling up methods currently in use to produce CO_2 for beverage and chemical applications.[151] However, the costs—in terms of energy consumed by the capture process and added capital and operating expenses—would be very high. The energy penalty of adding such technology to the plant would equal 24 to 40 percent of the energy produced by the plant.[152] A recent MIT study estimates that adding CO_2 capture technology to a conventional coal plant and disposing of the CO_2 in geological formations would increase the plant's levelized cost by nearly $30/MWh or 74 percent.[153]

Thus, there is no technological solution that can be reasonably expected to buffer a conventional coal plant from the financial risk associated with CO_2 regulation. Whether the plant operator ultimately pays for emission allowances or installs technology to capture and dispose of the CO_2, it runs a high risk of greatly increased costs.

VI. Regulators should protect ratepayers from future CO_2 costs by refusing to authorize new coal plants; alternatively, they should clearly place the risk of future CO_2 costs on utility shareholders rather than on ratepayers.

Currently, a utility's environmental compliance costs are routinely passed through to ratepayers as a cost of providing electricity. In particular, costs of buying pollution allowances (such as the sulfur dioxide allowances coal operators purchase today) are considered operating expenses recoverable through rates. This regulatory pattern of

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150 Public Service Commission of Wisconsin, Weston Unit 4 Power Plant Final Environmental Impact Statement, Volume 1, July 2004, 134 and 145. Online at *http://psc.wi.gov/utilityinfo/electric/cases/weston/document/Volume1/W4_FEIS.pdf*.

151 IPCC, "Carbon Dioxide Capture and Storage," 121. Current unit capacities would have to be increased by a factor of between 20 and 50 for deployment at a 500 MW coal plant.

152 Ibid, Summary for Policymakers, 4.

153 Ram C. Sekar, John E. Parsons, Howard J. Herzog, and Henry D. Jacoby, "Future Carbon Regulations and Current Investments in Alternative Coal-Fired Power Plant Designs," MIT Joint Program on the Science and Policy of Global Change, December 2005, 4.

treating pollution allowance costs as operating expenses means that utilities may feel confident that they can also recover any future CO_2 allowance costs through their rates.

Such confidence, however, means a utility operating in a regulated environment has little incentive to assess CO_2 allowance costs in a serious way, even when contemplating major new long-term investments. From a societal standpoint, this is a financial disaster waiting to happen; the financial risks of building a new coal plant are very high, but the party making the investment is not deterred because it does not feel at risk.

It is, of course, up to state regulators to make sure this financial disaster is avoided and that ratepayers are protected. By far the best way to do that is to deny approval of the proposed coal plant and encourage the utility to pursue less financially risky alternatives.

However, if regulators do approve construction of a proposed plant, they should ensure that the utility has an incentive to minimize this risk as it emerges by warning it that future CO_2 allowance costs will not be recoverable through rates. This is particularly important given how rapidly climate change policy is evolving and how long it takes to build a coal plant. Because utilities would for some time have the ability to cancel or downsize new plants in response to the growing risk of CO_2 costs, regulators should give them the incentive to monitor and respond to that risk. Shifting the risk of future CO_2 regulations onto utilities may be inconsistent with current rate treatment of pollution allowances, but it is fully consistent with underlying ratemaking principles and the case law related to investments in new baseload plants.

In the late 1960s and 1970s, many of the nation's utilities believed two things that turned out to be wrong: that electricity demand would keep growing at a fast rate and that nuclear power would be an inexpensive way to meet that demand. These mistaken beliefs resulted in substantial excess baseload capacity in the early 1980s (largely from unneeded coal plants), many abandoned nuclear plants, and disputes around the nation about whether the costs of these mistakes should be paid by utility shareholders or ratepayers.

The regulatory decisions made during this era typically allocated at least a share of excess costs to shareholders, and articulated standards intended to give utilities a stronger incentive to avoid such unwise investments in the future.[154] Now that utilities are again in the midst of a baseload power plant construction boom based on risky assumptions, these standards are again highly relevant.

Two complementary regulatory approaches emerge in these disputes: the "prudent investment approach" and the "shared costs approach." Both approaches are intended, in part, to create incentives for utilities to continually rethink their investment decisions in

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[154] For overviews of these cases see Richard J. Pierce, Jr., "The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity," 132 *U. Pa. L. Rev*. 497 (1984); "Abandoned Nuclear Plant Recovery," 83 *ALR*4th 183 (1991); and Roger D. Colton, "Excess Capacity: Who Gets the Charge from the Power Plant?" 34 *Hastings L.J*. 1133 (1983).

light of emerging events (rather than sticking to a chosen path even when subsequent developments clearly make that path unwise).

Under the prudent investment approach all or part of a utility's investment can be excluded from rates if any decision made by the utility in relation to that investment is found to be imprudent. This could include the decision to build a power plant and the subsequent decision not to cancel it after changing circumstances show the project to be unwise.[155]

While this principle has often been invoked by utilities seeking to recover from unsuccessful investments that appeared to be prudent when they were initially made,[156] the principle is also intended to protect ratepayers from unwise utility decisions.[157] Over the years, regulators have denied rate recovery for some enormous investments judged to be imprudent, including costs related to abandoned nuclear power plant construction plans[158] and coal plants that were built but created excess capacity.[159]

To determine whether an investment was prudent, courts consider what a utility knew or should have known when the investment was made, and any alternative generating options that were available at the time. The inquiry not only focuses on the initial decision to build a plant, but also on the subsequent, ongoing decisions to continue pursuing construction even after events such as the adoption of a new regulatory approach greatly increased cost estimates beyond those originally projected. As parts I through V show, building a coal plant without reasonably factoring in the substantial financial risk associated with coming climate laws is clearly imprudent. On these grounds alone, regulators would be justified in disallowing rate recovery of CO_2 costs.

However, an investment need not be deemed imprudent for recovery to be disallowed. The U.S. Supreme Court has explicitly upheld the authority of state regulators to limit a utility's recovery for an investment that appeared prudent at the time it was made but ultimately proved unwise.[160] States have considerable discretion to set rates that appropriately balance the interests of shareholders and ratepayers, and some have adopted approaches that divide financial risks between these parties. State regulators have particularly used this shared costs approach in cases of excess capacity built as a result of inaccurate demand forecasts, because they concluded that placing all the risk on ratepayers is unfair and creates the wrong incentives for utility management. In 1982, for example, Iowa regulators refused to pass on to ratepayers all the costs a utility incurred in building what later proved to be excess generating capacity, even though the decision to build was reasonable when made. The Iowa commission explained its reasoning this way:

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[155] See Pierce, supra, p. 7.
[156] See Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S.Ct. 609 (1989).
[157] Verizon Communications Inc. v. FCC, 535 U.S. 467, 122 S.Ct. 1646, 1659 (2002).
[158] See e.g., Association of Businesses Advocating Tariff Equity v. Public Service Commission, 527 N.W.2d 533 (Mich. App. 1994); In Re Interstate Power Company, 416 NW2d 800 (Minn. App. 1987); Re Boston Edison Co., 46 PUR4th 431 (Mass DPU, 1982), aff'd 455 NE2d 414.
[159] Gulf Power Company v. Florida Public Service Commission, 453 So.2d 799 (Fla. 1984);
[160] Duquesne Light Co. v. Barasch, 488 U.S. 299, 109 S. Ct. 609 (1989).

> *"In the real world of competitive enterprise, management officials must continuously rethink prior decisions as new events unfold. Those who fail to stay on top of current events lose out to their competition. Iowa utilities should also maintain surveillance over costs associated with a particular decision, and in the absence of the kind of incentive provided by a competitor, the responsibility falls upon us to provide the requisite incentive."*[161]

The Wisconsin Supreme Court agreed with Iowa's shared costs approach and recognized the authority of Wisconsin regulators to apply it in the same context.[162] Pennsylvania regulators applied similar reasoning in an excess capacity case, noting that while the investments were prudent and the excess capacity was no fault of the utility or its investors, "neither was it the fault of ratepayers. Under these circumstances there must be some sharing of the risk associated with bringing these large plants on line."[163]

North Dakota regulators took a similar approach in response to excess capacity created by a coal plant, refusing to allow all the costs to be passed on to ratepayers. Though they did not deem the utility's investment imprudent, regulators felt it was "unreasonable to expect ratepayers to completely absorb the risk" of excess capacity, and that "there must be some risk placed on the utility and there must be some incentive for the pool and the individual utility member to continuously strive for accurate and precise management" of investments in baseload capacity. [164]

Both the prudent investment approach and the shared costs approach recognize the importance of giving utilities a strong incentive to avoid making investment mistakes, especially when building expensive, long-lived baseload plants. And both lines of cases stress how important it is for utility management to keep track of changes that affect the wisdom of the utility's investment during the period after a plant receives regulatory approval but before construction is completed.

These cases grew out of an era (the 1970s) when utilities making large investments in baseload capacity were surprised by events beyond their control—primarily the OPEC embargo, which led to slower growth in energy demand, and the Three Mile Island accident, which resulted in stricter safety standards and higher construction costs. Once again, utilities are making huge investments in baseload power, but this time the global changes that threaten the economic viability of these investments are far more predictable than they were in the past. Indeed, they are looming, and they threaten to substantially increase the cost of energy from new coal plants. It is even more critical today that utilities be given a strong incentive to track regulatory developments and continually re-examine their construction decisions in light of those developments.

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[161] Re Iowa Public Service Company, 46 PUR4th 339, 368-69 (IA Commerce Commission, 1982).
[162] Madison Gas and Electric Company v. Public Service Commission of Wisconsin, 325 N.W.2d 339 (Wis. 1982).
[163] Pennsylvania Public Utility Commission v. Philadelphia Electric Co., 37 PUR4th 381, 387 (Pa. Public Utility Commission, 1980).
[164] Re Montana-Dakota Utilities Co., 44 PUR4th 249, 255 (N.D. PSC 1981); see also Re Otter Tail Power Company, 44 PUR4th 219 (N.D. PSC 1981).

Regulators can create such an incentive by determining, as a condition of plant approval, that future CO_2 costs will be borne by utility shareholders rather than ratepayers.

VII. Conclusion

The fight against global warming will unquestionably change the laws, economics, and technology of power production and use. Many different groups have a role to play in helping ensure our society responds sensibly to these changes.

- Utilities should factor future CO_2 costs into their resource planning and procurement, aggressively pursue conservation, efficiency and renewable energy, and at the very least defer making major coal plant construction decisions until they have a clearer picture of the regulatory risks and technological opportunities ahead.

- Regulators should insist that utilities take the above steps. They should also protect ratepayers by refusing to authorize the construction of new conventional coal plants, which are premised on the regulatory conditions of the past, not those of the future. At the least, they should warn utility managers that shareholders will bear the risk that coal investments will result in excess carbon costs.

- Investors and shareholders should recognize the inevitability of CO_2 regulations and understand that utilities that behave imprudently by building coal plants despite these costs would, under existing regulatory principles, be prevented from recovering at least a portion of such costs in their rates. Shareholders should question utility management closely on how they are assessing and managing carbon risks, and require reporting and accountability. Long-term investors should favorably regard companies who are proactively considering and managing these risks effectively.

- Ratepayers and consumer groups should realize that the utilities building new coal plants will seek to recover all their costs, including CO_2 regulatory costs, from ratepayers. While legal principles support denying rate recovery of these costs, history shows that these cases are extremely contentious and expensive. A far better way for ratepayers and consumer groups to protect themselves from such financial risk is by resisting the construction of new conventional coal plants in the first place and by supporting investments in cleaner alternatives such as efficiency and renewable energy.

Building a major energy resource – especially one that costs as much and lasts as long as a coal plant -- is unavoidably an exercise in predicting the future. It cannot be prudently done without objectively analyzing the trends and potential risks that will shape the decades ahead. In the case of new coal plants, the critical trends are undeniable and moving with unstoppable momentum: CO_2 levels are rising to levels unseen on the planet in millions of years, global temperatures are setting new records, scientific evidence showing that our current energy path is leading to dangerous climate changes is mounting, and the policy response at every level of government is accelerating. To assume in the face of these trends that a new coal plant could be put into service and allowed to emit millions of tons of CO_2 for free for the next few decades is reckless, to say the least. New conventional coal plants in the age of global warming are not just bad policy – they are a bad investment, and one we cannot afford to make.

Climate Change and Power:

Carbon Dioxide Emissions Costs and Electricity Resource Planning

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Executive Summary

The fact of human-induced global climate change as a consequence of our greenhouse gas emissions is now well established, and the only remaining questions among mainstream scientists concern the nature and timing of future disruptions and dislocations and the magnitude of the socio-economic impacts. It is also generally agreed that different CO_2 emissions trajectories will lead to varying levels of environmental, economic, and social costs – which means that the more sharply and the sooner we can reduce emissions, the greater the avoided costs will be.

This report is designed to assist utilities, regulators, consumer advocates and others in projecting the future cost of complying with carbon dioxide regulations in the United States.[1] These cost forecasts are necessary for use in long-term electricity resource planning, in electricity resource economics, and in utility risk management.

We recognize that there is considerable uncertainty inherent in projecting long-term carbon emissions costs, not least of which concerns the timing and form of future emissions regulations in the United States. However, this uncertainty is no reason to ignore this very real component of future production cost. In fact, this type of uncertainty is similar to that of other critical electricity cost drivers such as fossil-fuel prices.

Accounting for Climate Change Regulations in Electricity Planning

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions, but has only 4.6 percent of the population.

Within the United States, the electricity sector is responsible for roughly 39% of CO_2 emissions. Within the electricity industry, roughly 82% of CO_2 emissions come from coal-fired plants, roughly 13% come from gas-fired plants, and roughly 5% come from oil-fired plants.

Because of its contribution to US and worldwide CO_2 emissions, the US electricity industry will clearly need to play a critical role in reducing greenhouse gas (GHG) emissions. In addition, the electricity industry is composed of large point sources of emissions, and it is often easier and more cost-effective to control emissions from large sources than multiple small sources. Analyses by the US Energy Information Administration indicate that 65% to 90% of energy-related carbon dioxide emissions reductions are likely to come from the electric sector under a wide range of economy-wide federal policy scenarios.[2]

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[1] This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

[2] EIA 2003, page 13; EIA 2004, page 5; EIA 2006, page 19.

In this context, the failure of entities in the electric sector to anticipate the future costs associated with carbon dioxide regulations is short-sighted, economically unjustifiable, and ultimately self-defeating. Long-term resource planning and investment decisions that do not quantify the likely future cost of CO_2 regulations will understate the true cost of future resources, and thus will result in uneconomic, imprudent decisions. Generating companies will naturally attempt to pass these unnecessarily high costs on to electricity ratepayers. Thus, properly accounting for future CO_2 regulations is as much a consumer issue as it is an issue of prudent resource selection.

Some utility planners argue that the cost of complying with future CO_2 regulations involves too much uncertainty, and thus they leave the cost out of the planning process altogether. This approach results in making an implicit assumption that the cost of complying with future CO_2 regulations will be zero. This assumption of zero cost will apply to new generation facilities that may operate for 50 or more years into the future. In this report, we demonstrate that under all reasonable forecasts of the near- to mid-term future, the cost of complying with CO_2 regulations will certainly be greater than zero.

Federal Initiatives to Regulate Greenhouse Gases

The scientific consensus on climate change has spurred efforts around the world to reduce greenhouse gas emissions, many of which are grounded in the United Nations Framework Convention on Climate Change (UNFCCC). The United States is a signatory to this convention, which means that it has agreed to a goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." However, the United States has not yet agreed to the legally binding limits on greenhouse gas emissions contained in the Kyoto Protocol, a supplement to the UNFCCC.

Table ES-1. Summary of Federal Mandatory Emission Reduction Legislation

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Nonetheless, there have been several important attempts at the federal level to limit the emissions of greenhouse gases in the United States. Table ES-1 presents a summary of federal legislation that has been introduced in recent years. Most of this legislation includes some form of mandatory national limits on the emissions of greenhouse gases, as well as market-based cap and trade mechanisms to assist in meeting those limits.

State and Regional Initiatives to Regulate Greenhouse Gases

Many states across the country have not waited for federal policies, and are developing and implementing climate change-related policies that have a direct bearing on electric resource planning. States, acting individually and through regional coordination, have been the leaders on climate change policies in the United States.

State policies generally fall into the following categories: (a) direct policies that require specific emission reductions from electric generation sources; (b) indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (c) legal proceedings; or (d) voluntary programs including educational efforts and energy planning. Table ES-2 presents a summary of types of policies with recent state policies on climate change listed on the right side of the table.

Table ES-2. Summary of Individual State Climate Change Policies

Type of Policy	State Examples
Direct	
• Power plant emission restrictions (e.g. cap or emission rate)	• MA, NH
• New plant emission restrictions	• OR, WA
• State GHG reduction targets	• CT, NJ, ME, MA, CA, NM, NY, OR, WA
• Fuel/generation efficiency	• CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy)	
• Load-based GHG cap	• CA
• GHG in resource planning	• CA, WA, OR, MT, KY
• Renewable portfolio standards	• 22 states and D.C.
• Energy efficiency/renewable charges and funding; energy efficiency programs	• More than half the states
• Net metering, tax incentives	• 41 states
Lawsuits	
• States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act	• States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI
• States sue individual companies to reduce GHG emissions	• NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states require that regulated utilities evaluate costs or risks associated with greenhouse gas emissions regulations in long-range planning or resource procurement. Some of the states require that companies use a specific value, while other states require that companies consider the risk of future regulation in their planning process. Table ES-3 summarizes state requirements for considering greenhouse gas emissions in electricity resource planning.

Table ES-3. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

States are not just acting individually; there are several examples of innovative regional policy initiatives. To date, there are regional initiatives including Northeastern and Mid-Atlantic states (CT, DE, MD, ME, NH, NJ, NY, and VT), West Coast states (CA, OR, WA), Southwestern states (NM, AZ), and Midwestern states (IL, IA, MI, MN, OH, WI).

The Northeastern and Mid-Atlantic states recently reached agreement on the creation of the Regional Greenhouse Gas Initiative (RGGI); a multi-year cooperative effort to design a regional cap and trade program covering CO_2 emissions from power plants in the region. The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes.
- Certain offset provisions that increase flexibility to moderate price impacts.
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.

Electric Industry Actions to Address Greenhouse Gases

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have begun to evaluate the risks associated with future greenhouse gas regulation and take steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints.

Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013."

In addition, leaders of electric companies such as Duke and Exelon have vocalized support for mandatory national carbon regulation. These companies urge a mandatory federal policy, stating that climate change is a pressing issue that must be resolved, that voluntary action is not sufficient, and that companies need regulatory certainty to make appropriate decisions. Even companies that do not advocate federal requirements, anticipate their adoption and urge regulatory certainty. Several companies have established greenhouse gas reduction goals for their company.

Several electric utilities and electric generation companies have incorporated specific forecasts of carbon regulation and costs into their long term planning practices. Table ES-4 illustrates the range of carbon cost values, in \$/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table ES-4. CO_2 Cost Estimates Used in Electricity Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2004, pages 62-63; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

Synapse Forecast of Carbon Dioxide Allowance Prices

This report presents our current forecast of the most likely costs of compliance with future climate change regulations. In making this forecast we review a range of current estimates from a variety of different sources. We review the results of several analyses of federal policy proposals, and a few analyses of the Kyoto Protocol. We also look briefly at carbon markets in the European Union to demonstrate the levels at which carbon dioxide emissions are valued in an active market.

Figure ES-1 presents CO_2 allowance price forecasts from the range of recent studies that we reviewed. All of the studies here are based on the costs associated with complying with potential CO_2 regulations in the United States. The range of these price forecasts reflects the range of policy initiatives that have been proposed in the United States, as well as the diversity of economic models and methodologies used to estimate their price impacts.

Figure ES-1 superimposes the Synapse long term forecasts of CO_2 allowance prices upon the other forecasts gleaned from the literature. In order to help address the uncertainty involved in forecasting CO_2 prices, we present a "base case" forecast as well as a "low case" and a "high case." All three forecasts are based on our review of both regulatory trends and economic models, as outlined in this document.

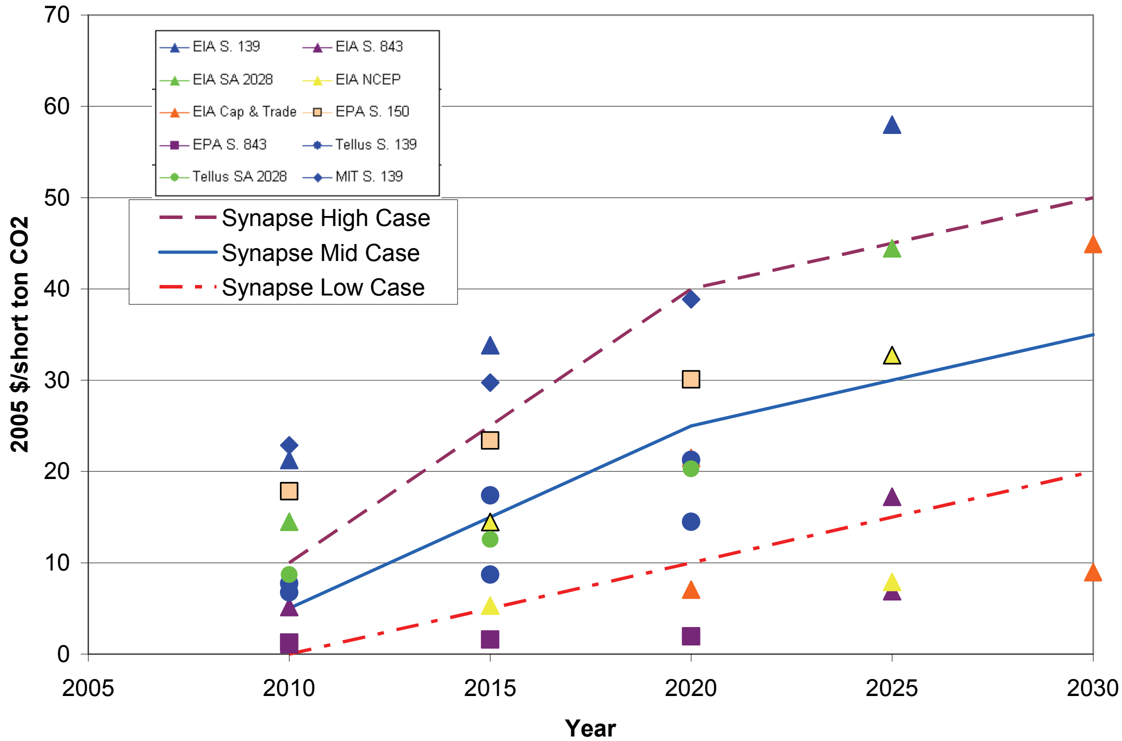

Figure ES-1. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.3.

As with any forecast, our forecast is likely to be revised over time as the form and timing of carbon emission regulations come increasingly into focus. It is our judgment that this range represents a reasonable quantification of what is known today about future carbon emissions costs in the United States. As such, it is appropriate for use in long range resource planning purposes until better information or more clarity become available.

Additional Costs Associated with Greenhouse Gases

This report summarizes current policy initiatives and costs associated with greenhouse gas emissions from the electric sector. It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

In keeping with these findings, the European Union has adopted an objective of keeping global surface temperature increases to 2 degrees centigrade above pre-industrial levels. The EU Environment Council concluded in 2005 that this goal is likely to require emissions reductions of 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050.

In other words, incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates, but it does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

1. Introduction

Climate change is not only an "environmental" issue. It is at the confluence of energy and environmental policy, posing challenges to national security, economic prosperity, and national infrastructure. Many states do not require greenhouse gas reductions, nor do we yet have a federal policy requiring greenhouse gas reductions in the United States; thus many policy makers and corporate decision-makers in the electric sector may be tempted to consider climate change policy a hazy future possibility rather than a current factor in resource decisions. However, such a "wait and see" approach is imprudent for resource decisions with horizons of more than a few years. Scientific developments, policy initiatives at the local, state, and federal level, and actions of corporate leaders, all indicate that climate change policy will affect the electric sector – the question is not "whether" but "when," and in what magnitude.

Attention to global warming and its potential environmental, economic, and social impacts has rapidly increased over the past few years, adding to the pressure for comprehensive climate change policy in the United States The April 3, 2006 edition of TIME Magazine reports the results of a new survey conducted by TIME, ABC News and Stanford University which reveals that more than 80 percent of Americans believe global warming is occurring, while nearly 90 percent are worried that warming presents a serious problem for future generations. The poll reveals that 75 percent would like the US government, US businesses, and the American people to take further action on global warming in the next year.[3]

In the past several years, climate change has emerged as a significant financial risk for companies. A 2002 report from the investment community identifies climate change as representing a potential multi-billion dollar risk to a variety of US businesses and industries.[4] Addressing climate change presents particular risk and opportunity to the electric sector. Because the electric sector (and associated emissions) continue to grow, and because controlling emissions from large point sources (such as power plants) is easier, and often cheaper, than small disparate sources (like automobiles), the electric sector is likely to be a prime component of future greenhouse gas regulatory scenarios. The report states that "climate change clearly represents a major strategic issue for the electric utilities industry and is of relevance to the long-term evolution of the industry and possibly the survival of individual companies." Risks to electric companies include the following:

- Cost of reducing greenhouse gas emissions and cost of investment in new, cleaner power production technologies and methods;
- Higher maintenance and repair costs and reliability concerns due to more frequent weather extremes and climatic disturbance; and

[3] TIME/ABC News/Stanford University Poll, appearing in April 3, 2006 issue of Time Magazine.

[4] Innovest Strategic Value Advisors; "Value at Risk: Climate Change and the Future of Governance;" The Coalition for Environmentally Responsible Economies; April 2002.

- Growing pressure from customers and shareholders to address emissions contributing to climate change.[5]

A subsequent report, "Electric Power, Investors, and Climate Change: A Call to Action," presents the findings of a diverse group of experts from the power sector, environmental and consumer groups, and the investment community.[6] Participants in this dialogue found that greenhouse gas emissions, including carbon dioxide emissions, will be regulated in the United States; the only remaining issue is when and how. Participants also agreed that regulation of greenhouse gases poses financial risks and opportunities for the electric sector. Managing the uncertain policy environment on climate change is identified as "one of a number of significant environmental challenges facing electric company executives and investors in the next few years as well as the decades to come."[7] One of the report's four recommendations is that investors and electric companies come together to quantify and assess the financial risks and opportunities of climate change.

In a 2003 report for the World Wildlife Fund, Innovest Strategic Advisors determined that climate policy is likely to have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities and other power plant owners.[8] The report found that, even under conservative scenarios, additional costs could exceed 10 percent of 2002 earnings, though there are also significant opportunities. While utilities and non-utility generation owners have many options to deal with the impact of increasing prices on CO_2 emissions, doing nothing is the worst option. The report concludes that a company's profits could even increase with astute resource decisions (including fuel switching or power plant replacement).

Increased CO_2 emissions from fossil-fired power plants will not only increase environmental damages and challenges to socio-economic systems; on an individual company level they will also increase the costs of complying with future regulations – costs that are likely to be passed on to all customers. Power plants built today can generate electricity for as long as 50 years or more into the future.[9]

As illustrated in the table below, factoring costs associated with future regulations of carbon dioxide has an impact on the costs of resources. Resources with higher CO_2 emissions have a higher CO_2 cost per megawatt-hour than those with lower emissions.

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[5] Ibid., pages 45-48.

[6] CERES; "Electric Power, Investors, and Climate Change: A Call to Action;" September 2003.

[7] Ibid., p. 6

[8] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[9] Biewald et. al.; "A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the US Electricity System;" prepared for the National Association of State PIRGs; June 11, 2004.

Table I.1. Comparison of CO_2 costs per MWh for Various Resources

Resource	Scrubbed Coal (Bit)	Scrubbed Coal (Sub)	IGCC	Combined Cycle	Source Notes
Size	600	600	550	400	1
CO_2 (lb/MMBtu)	205.45	212.58	205.45	116.97	2, 3
Heat Rate (Btu/kWh)	8844	8844	8309	7196	1
CO_2 Price (2005$/ton)	19.63	19.63	19.63	19.63	4
CO_2 Cost per MWh	$17.83	$18.45	$16.75	$8.26	

1 - From AEO 2006
2 - From EIA's Electric Power Annual 2004, page 76
3 - IGCC emission rate assumed to be the same as the bituminous scrubbed coal rate
4 - From Synapse's carbon emissions price forecast levelized from 2010-2040 at a 7.32% real discount rate

Many trends in this country show increasing pressure for a federal policy requiring greenhouse gas emissions reductions. Given the strong likelihood of future carbon regulation in the United States, the contributions of the power sector to our nation's greenhouse gas emissions, and the long lives of power plants, utilities and non-utility generation owners should include carbon cost in all resource evaluation and planning.

The purpose of this report is to identify a reasonable basis for anticipating the likely cost of future mandated carbon emissions reductions for use in long-term resource planning decisions.[10] Section 2 presents information on US carbon emissions. Section 3 describes recent scientific findings on climate change. Section 4 describes international efforts to address the threat of climate change. Section 5 summarizes various initiatives at the state, regional, and corporate level to address climate change. Finally, section 6 summarizes information that can form the basis for forecasts of carbon allowance prices; and provides a reasonable carbon allowance price forecast for use in resource planning and investment decisions in the electric sector.

2. Growing scientific evidence of climate change

In 2001 the Intergovernmental Panel on Climate Change issued its Third Assessment Report.[11] The report, prepared by hundreds of scientists worldwide, concluded that the earth is warming, that most of the warming over the past fifty years is attributable to human activities, and that average surface temperature of the earth is likely to increase

[10] This paper focuses on anticipating the cost of future emission reduction requirements. This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

[11] Intergovernmental Panel on Climate Change, *Third Assessment Report*, 2001.

between 1.4 and 5.8 degrees Centigrade during this century, with a wide range of impacts on the natural world and human societies.

Scientists continue to explore the possible impacts associated with temperature increase of different magnitudes. In addition, they are examining a variety of possible scenarios to determine how much the temperature is likely to rise if atmospheric greenhouse gas concentrations are stabilized at certain levels. The consensus in the international scientific community is that greenhouse gas emissions will have to be reduced significantly below current levels. This would correspond to levels much lower than those limits underlying our CO_2 price forecasts. In 2001 the Intergovernmental Panel on Climate Change reported that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to keep global warming in the vicinity of a 2-3 degree centigrade temperature increase.[12]

Since 2001 the evidence of climate change, and human contribution to climate change, is even more compelling. In June 2005 the National Science Academies from eleven major nations, including the United States, issued a Joint Statement on a Global Response to Climate Change.[13] Among the conclusions in the statement were that

- Significant global warming is occurring;
- It is likely that most of the warming in recent decades can be attributed to human activities;
- The scientific understanding of climate change is now sufficiently clear to justify nations taking prompt action;
- Action taken now to reduce significantly the build-up of greenhouse gases in the atmosphere will lessen the magnitude and rate of climate change;
- The Joint Academies urge all nations to take prompt action to reduce the causes of climate change, adapt to its impacts and ensure that the issue is included in all relevant national and international strategies.

There is increasing concern in the scientific community that the earth may be more sensitive to global warming than previously thought. Increasing attention is focused on understanding and avoiding dangerous levels of climate change. A 2005 Scientific Symposium on Stabilization of Greenhouse Gases reached the following conclusions:[14]

[12] IPCC, *Climate Change 2001: Synthesis Report*, Fourth Volume of the IPCC Third Assessment Report. IPCC 2001. Question 6.

[13] *Joint Science Academies' Statement: Global Response to Climate Change*, National Academies of Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, United Kingdom, and United States, June 7, 2005.

[14] UK Department of Environment, Food, and Rural Affairs, *Avoiding Dangerous Climate Change – Scientific Symposium on Stabilization of Greenhouse Gases, February 1-3, 2005 Exeter, U.K. Report of the International Scientific Steering Committee,* May 2005. http://www.stabilisation2005.com/Steering_Commitee_Report.pdf

- There is greater clarity and reduced uncertainty about the impacts of climate change across a wide range of systems, sectors and societies. In many cases the risks are more serious than previously thought.
- Surveys of the literature suggest increasing damage if the globe warms about 1 to 3^0C above current levels. Serious risk of large scale, irreversible system disruption, such as reversal of the land carbon sink and possible de-stabilisation of the Antarctic ice sheets is more likely above 3^0C.
- Many climate impacts, particularly the most damaging ones, will be associated with an increased frequency or intensity of extreme events (such as heat waves, storms, and droughts).
- Different models suggest that delaying action would require greater action later for the same temperature target and that even a delay of 5 years could be significant. If action to reduce emissions is delayed by 20 years, rates of emission reduction may need to be 3 to 7 times greater to meet the same temperature target.

As scientific evidence of climate change continues to emerge, including unusually high temperatures, increased storm intensity, melting of the polar icecaps and glaciers worldwide, coral bleaching, and sea level rise, pressure will continue to mount for concerted governmental action on climate change.[15]

3. US carbon emissions

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions from fossil fuel consumption, but has only 4.6 percent of the population. According to the International Energy Agency, 80 percent of 2002 global energy-related CO_2 emissions were emitted by 22 countries – from all world regions, 12 of which are OECD countries. These 22 countries also produced 80 percent of the world's 2002 economic output (GDP) and represented 78 percent of the world's Total Primary Energy Supply.[16] Figure 3.1 shows the top twenty carbon dioxide emitters in the world.

[15] Several websites provide summary information on climate change science including www.ipcc.org www.nrdc.org, www.ucsusa.org, and www.climateark.org.

[16] International Energy Agency, "CO_2 from Fuel Combustion – Fact Sheet," 2005

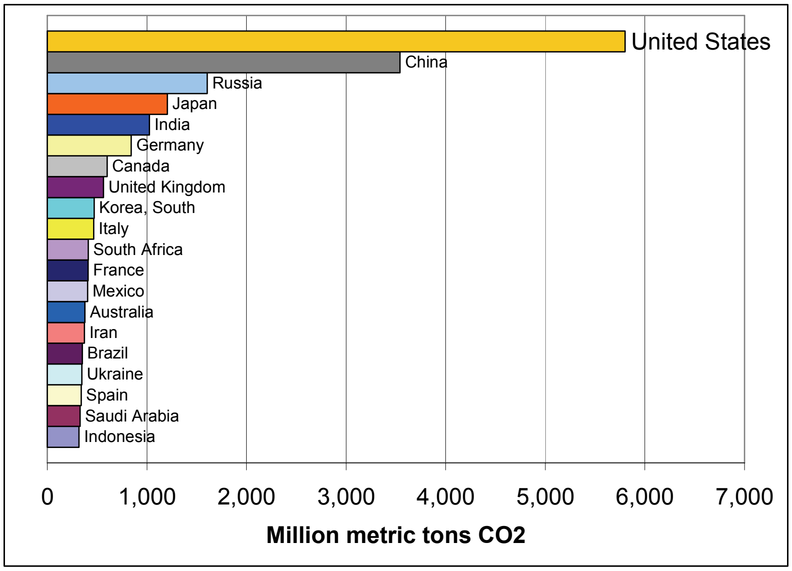

Figure 3.1. Top Worldwide Emitters of Carbon Dioxide in 2003

Source: Data from EIA Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2003, July 11, 2005

Emissions in this country in 2004 were roughly divided among three sectors: transportation (1,934 million metric tons CO_2), electric generation (2,299 million metric tons CO_2), and other (which includes commercial and industrial heat and process applications – 1,673 million metric tons CO_2). These emissions, largely attributable to the burning of fossil fuels, came from combustion of oil (44%), coal (35.4%), and natural gas (20.4%). Figure 3.2 shows emissions from the different sectors, with the electric sector broken out by fuel source.

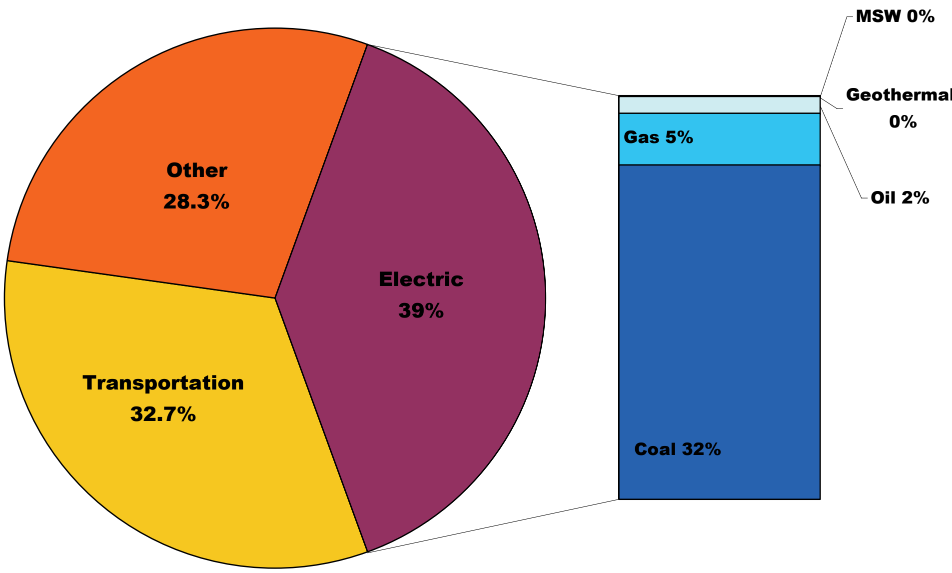

Figure 3.2. US CO_2 Emissions by Sector in 2004
Source: Data from EIA Emissions of Greenhouse Gases in the United States 2004, December 2005

Recent analysis has shown that in 2004, power plant CO_2 emissions were 27 percent higher than they were in 1990.[17] US greenhouse gas emissions per unit of Gross Domestic Product (GDP) fell from 677 metric tons per million 2000 constant dollars of GDP (MTCO2e/$Million GDP) in 2003 to 662 MTCO2e /$Million GDP in 2004, a decline of 2.1 percent.[18] However, while the carbon intensity of the US economy (carbon emissions per unit of GDP) fell by 12 percent between 1991 and 2002, the carbon intensity of the electric power sector held steady.[19] This is because the carbon efficiency gains from the construction of efficient and relatively clean new natural gas plants have been offset by increasing reliance on existing coal plants. Since federal acid rain legislation was enacted in 1990, the average rate at which existing coal plants are operated increased from 61 percent to 72 percent. Power plant CO_2 emissions are concentrated in states along the Ohio River Valley and in the South. Five states – Indiana, Ohio, Pennsylvania, Texas, and West Virginia – are the source of 30 percent of the electric power industry's NO_x and CO_2 emissions, and nearly 40 percent of its SO_2 and mercury emissions.

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[17] EIA, "Emissions of Greenhouse Gases in the United Sates, 2004;" Energy Information Administration; December 2005, xiii

[18] EIA *Emissions of Greenhouse Gases in the United States 2004,* December 2005.

[19] Goodman, Sandra; "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2002;" CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG); April 2004. An updated "Benchmarking Study" has been released: Goodman, Sandra and Walker, Michael. "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2004." CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG). April 2006.

4. Governments worldwide have agreed to respond to climate change by reducing greenhouse gas emissions

The prospect of global warming and associated climate change has spurred one of the most comprehensive international treaties on environmental issues.[20] The 1992 United Nations Framework Convention on Climate Change has almost worldwide membership; and, as such, is one of the most widely supported of all international environmental agreements.[21] President George H.W. Bush signed the Convention in 1992, and it was ratified by Congress in the same year. In so doing, the United States joined other nations in agreeing that "The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities."[22] Industrialized nations, such as the United States, and Economies in Transition, known as Annex I countries in the UNFCCC, agree to adopt climate change policies to reduce their greenhouse gas emissions.[23] Industrialized countries that were members of the Organization for Economic Cooperation and Development (OECD) in 1992, called Annex II countries, have the further obligation to assist developing countries with emissions mitigation and climate change adaptation.

Following this historic agreement, most Parties to the UNFCCC adopted the Kyoto Protocol on December 11, 1997. The Kyoto Protocol supplements and strengthens the Convention; the Convention continues as the main focus for intergovernmental action to combat climate change. The Protocol establishes legally-binding targets to limit or reduce greenhouse gas emissions.[24] The Protocol also includes various mechanisms to cut emissions reduction costs. Specific rules have been developed on emissions sinks, joint implementation projects, and clean development mechanisms. The Protocol envisions a long-term process of five-year commitment periods. Negotiations on targets for the second commitment period (2013-2017) are beginning.

The Kyoto targets are shown below, in Table 4.1. Only Parties to the Convention that have also become Parties to the Protocol (i.e. by ratifying, accepting, approving, or acceding to it), are bound by the Protocol's commitments, following its entry into force in

[20] For comprehensive information on the UNFCC and the Kyoto Protocol, see UNFCC, "Caring for Climate: a guide to the climate change convention and the Kyoto Protocol," issued by the Climate Change Secretariat (UNFCC) Bonn, Germany. 2003. This and other publications are available at the UNFCCC's website: http://unfccc.int/.

[21] The First World Climate Conference was held in 1979. In 1988, the World Meteorological Society and the United Nations Environment Programme created the Intergovernmental Panel on Climate Change to evaluate scientific information on climate change. Subsequently, in 1992 countries around the world, including the United States, adopted the United Nations Framework Convention on Climate Change.

[22] From Article 3 of the United Nations Framework Convention on Climate Change, 1992.

[23] One of obligations of the United States and other industrialized nations is to a National Report describing actions it is taking to implement the Convention

[24] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

February 2005.[25] The individual targets for Annex I Parties add up to a total cut in greenhouse-gas emissions of at least 5 percent from 1990 levels in the commitment period 2008-2012.

Only a few industrialized countries have not signed the Kyoto Protocol; these countries include the United States, Australia, and Monaco. Of these, the United States is by far the largest emitter with 36.1 percent of Annex I emissions in 1990; Australia and Monaco were responsible for 2.1 percent and less than 0.1 percent of Annex I emissions, respectively. The United States did not sign the Kyoto protocol, stating concerns over impacts on the US economy and absence of binding emissions targets for countries such as India and China. Many developing countries, including India, China and Brazil have signed the Protocol, but do not yet have emission reduction targets.

In December 2005, the Parties agreed to final adoption of a Kyoto "rulebook" and a two-track approach to consider next steps. These next steps will include negotiation of new binding commitments for Kyoto's developed country parties, and, a nonbinding "dialogue on long-term cooperative action" under the Framework Convention.

Table 4.1. Emission Reduction Targets Under the Kyoto Protocol[26]

Country	**Target**: change in emissions from 1990** levels by 2008/2012
EU-15*, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
United States***	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0
Norway	+1%
Australia***	+8%
Iceland	+10%

** The EU's 15 member States will redistribute their targets among themselves, as allowed under the Protocol. The EU has already reached agreement on how its targets will be redistributed.*
*** Some Economies In Transition have a baseline other than 1990.*
**** The United States and Australia have indicated their intention not to ratify the Kyoto Protocol.*

As the largest single emitter of greenhouse gas emissions, and as one of the only industrialized nations not to sign the Kyoto Protocol, the United States is under significant international scrutiny; and pressure is building for the United States to take more initiative in addressing the emerging problem of climate change. In 2005 climate change was a priority at the G8 Summit in Gleneagles, with the G8 leaders agreeing to "act with resolve and urgency now" on the issue of climate change.[27] The leaders

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[25] Entry into force required 55 Parties to the Convention to ratify the Protocol, including Annex I Parties accounting for 55 percent of that group's carbon dioxide emissions in 1990. This threshold was reached when Russia ratified the Protocol in November 2004. The Protocol entered into force February 16, 2005.

[26] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[27] G8 Leaders, *Climate Change, Clean Energy, and Sustainable Development*, Political Statement and Action Plan from the G8 Leaders' Communiqué at the G8 Summit in Gleneagles U.K., 2005. Available

reached agreement that greenhouse gas emissions should slow, peak and reverse, and that the G8 nations must make "substantial cuts" in greenhouse gas emissions. They also reaffirmed their commitment to the UNFCCC and its objective of stabilizing greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system.

The EU has already adopted goals for emissions reductions beyond the Kyoto Protocol. The EU has stated its commitment to limiting global surface temperature increases to 2 degrees centigrade above pre-industrial levels.[28] The EU Environment Council concluded in 2005 that to meet this objective in an equitable manner, developed countries should reduce emissions 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050. A 2005 report from the European Environment Agency concluded that a 2 degree centigrade temperature increase was likely to require that global emissions increases be limited at 35% above 1990 levels by 2020, with a reduction by 2050 of between 15 and 50% below 1990 levels.[29] The EU has committed to emission reductions of 20-30% below 1990 levels by 2020, and reduction targets for 2050 are still under discussion.[30]

5. Legislators, state governmental agencies, shareholders, and corporations are working to reduce greenhouse gas emissions from the United States

There is currently no mandatory federal program requiring greenhouse gas emission reductions. Nevertheless, various federal legislative proposals are under consideration, and President Bush has acknowledged that humans are contributing to global warming. Meanwhile, state and municipal governments (individually and in cooperation), are leading the development and design of climate policy in the United States. Simultaneously, companies in the electric sector, acting on their own initiative or in compliance with state requirements, are beginning to incorporate future climate change policy as a factor in resource planning and investment decisions.

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at: http://www.g8.gov.uk/servlet/Front?pagename=OpenMarket/Xcelerate/ShowPage&c=Page&cid=1094235520309

[28] Council of the European Union, *Information Note – Brussels March 10, 2005.* http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

[29] European Environment Agency, *Climate Change and a European Low Carbon Energy System,* 2005. EEA Report No 1/2005. ISSN 1725-9177. http://reports.eea.europa.eu/eea_report_2005_1/en/Climate_change-FINAL-web.pdf

[30] Ibid; and European Parliament Press Release "Winning the Battle Against Climate Change" November 17, 2005. http://www.europarl.europa.eu/news/expert/infopress_page/064-2439-320-11-46-911-20051117IPR02438-16-11-2005-2005-false/default_en.htm

5.1 Federal initiatives

With ratification of the United Nations Framework Convention on Climate Change in 1992, the United States agreed to a goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[31] To date, the Federal Government in the United States has not required greenhouse gas emission reductions, and the question of what constitutes a dangerous level of human interference with the climate system remains unresolved. However, legislative initiatives for a mandatory market-based greenhouse gas cap and trade program are under consideration.

To date, the Bush Administration has relied on voluntary action. In July 2005, President Bush changed his public position on causation, acknowledging that the earth is warming and that human actions are contributing to global warming.[32] That summer, the Administration launched a new climate change pact between the United States and five Asian and Pacific nations aimed at stimulating technology development and inducing private investments in low-carbon and carbon-free technologies. The Asia-Pacific Partnership on Clean Development and Climate – signed by Australia, China, India, Japan, South Korea and the United States – brings some of the largest greenhouse gas emitters together; however its reliance on voluntary measures reduces its effectiveness.

The legislative branch has been more active in exploring mandatory greenhouse gas reduction policies. In June 2005, the Senate passed a sense of the Senate resolution recognizing the need to enact a US cap and trade program to slow, stop and reverse the growth of greenhouse gases. [33]

[31] The UNFCC was signed by President George H. Bush in 1992 and ratified by the Senate in the same year.

[32] "Bush acknowledges human contribution to global warming; calls for post-Kyoto strategy." Greenwire, July 6, 2005.

[33] US Senate, *Sense of the Senate Resolution on Climate Change,* US Senate Resolution 866; June 22, 2005. Available at: http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail&PressRelease_id=234715&Month=6&Year=2005&Party=0

Sense of the Senate Resolution – June 2005

> It is the sense of the Senate that, before the end of the 109th Congress, Congress should enact a comprehensive and effective national program of mandatory, market-based limits on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that
>
> (1) will not significantly harm the United States economy; and
>
> (2) will encourage complementary action by other nations that are major trading partners and key contributors to global emissions.

This Resolution built upon previous areas of agreement in the Senate, and provides a foundation for future agreement on a cap and trade program. On May 10, 2006 the House Appropriations Committee adopted very similar language supporting a mandatory cap on greenhouse gas emissions in a non-binding amendment to a 2007 spending bill.[34]

Several mandatory emissions reduction proposals have been introduced in Congress. These proposals establish emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. Federal proposals that would require greenhouse gas emission reductions are summarized in Table 5.1, below.

[34] "House appropriators OK resolution on need to cap emissions," Greenwire, May 10, 2005.

Table 5.1. Summary of Federal Mandatory Emission Reduction Proposals

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants >15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants >25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Landmark legislation that would regulate carbon, the Climate Stewardship Act (S.139), was introduced by Senators McCain and Lieberman in 2003, and received 43 votes in the Senate. A companion bill was introduced in the House by Congressmen Olver and Gilchrest. As initially proposed, the bill created an economy-wide two-step cap on greenhouse gas emissions. The bill was reintroduced in the 109th Congress on February 10, 2005; the revised Climate Stewardship Act, SA 2028, would create a national cap and trade program to reduce CO_2 to year 2000 emission levels over the period 2010 to 2015. Other legislative initiatives on climate change were also under consideration in the spring of 2005, including a proposal by Senator Jeffords (D-VT) to cap greenhouse gas emissions from the electric sector (S. 150), and an electric sector four-pollutant bill from Senator Carper (D-DE) (S. 843).

In 2006, the Senate appears to be moving beyond the question of whether to regulate greenhouse gas emissions, to working out the details of how to regulate greenhouse gas emissions. Senators Domenici (R-NM) and Bingaman (D-NM) are working on bi-partisan legislation based on the recommendations of the National Commission on Energy Policy (NCEP). The NCEP – a bipartisan group of energy experts from industry, government, labor, academia, and environmental and consumer groups – released a consensus strategy in December 2004 to address major long-term US energy challenges. Their report recommends a mandatory economy-wide tradable permits program to limit GHG. Costs would be capped at $7/metric ton of CO_2 equivalent in 2010 with the cap rising 5 percent annually.[35] The Senators are investigating the details of creating a mandatory economy-wide cap and trade system based on mandatory reductions in greenhouse gas intensity (measured in tons of emissions per dollar of GDP). In the spring of 2006, the Senate Energy and Natural Resources Committee held hearings to develop the details of a proposal.[36] During these hearings many companies in the electric power sector, such as Exelon, Duke Energy, and PNM Resources, expressed support for a mandatory national greenhouse gas cap and trade program.[37]

Two other proposals in early 2006 have added to the detail of the increasingly lively discussion of federal climate change strategies. Senator Feinstein (D-CA) issued a proposal for an economy-wide cap and trade system in order to further spur debate on the issue.[38] Senator Feinstein's proposal would cap emissions and seek reductions at levels largely consistent with the original McCain-Lieberman proposal. The most recent proposal to be added to the discussion is one by Reps. Tom Udall (D-NM) and Tom Petri (R-WI). The proposal includes a market-based trading system with an emissions cap to be established by the EPA about three years after the bill becomes law. The bill includes provisions to spur new research and development by setting aside 25 percent of the trading system's allocations for a new Energy Department technology program, and 10 percent of the plan's emission allowances to the State Department for spending on zero-carbon and low-carbon projects in developing nations. The bill would regulate greenhouse gas emissions at "upstream" sources such as coal mines and oil imports. Also,

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[35] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, pages 19-29.

[36] The Senators have issued a white paper, inviting comments on various aspects of a greenhouse gas regulatory system. See, Senator Pete V. Domenici and Senator Jeff Bingaman, "Design Elements of a Mandatory Market-based Greenhouse Gas Regulatory System," issued February 2, 2006.

[37] All of the comments submitted to the Senate Energy and Natural Resources Committee are available at: http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.View&IssueItem_ID=38

[38] Letter of Senator Feinstein announcing "Strong Economy and Climate Protection Act of 2006," March 20, 2006.

it would establish a "safety valve" initially limiting the price of a ton of carbon dioxide emission to $25.[39]

Figure 5.1 illustrates the anticipated emissions trajectories from the economy-wide proposals - though the most recent proposal in the House is not included due to its lack of a specified emissions cap.

Figure 5.1. Emission Trajectories of Proposed Federal Legislation

Anticipated emissions trajectories from federal proposals for economy-wide greenhouse gas cap and trade proposals (McCain Lieberman S.139 Climate Stewardship Act 2003, McCain-Lieberman SA 2028 Climate Stewardship Act 2005, National Commission on Energy Policy greenhouse gas emissions intensity cap, and Senator Feinstein's Strong Economy and Climate Protection Act). EIA Reference trajectory is a composite of Reference cases in EIA analyses of the above policy proposals.

The emissions trajectories contained in the proposed federal legislation are in fact quite modest compared with emissions reductions that are anticipated to be necessary to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that correspond to temperature increase of about 2 degrees centigrade. Figure 5.2 compares various emission reduction trajectories and goals in relation to a 1990 baseline. US federal proposals, and even Kyoto Protocol reduction targets, are small compared with the current EU emissions reduction target for 2020, and emissions reductions that will ultimately be necessary to cope with global warming.

[39] Press release, "Udall and Petri introduce legislation to curb global warming," March 29, 2006.

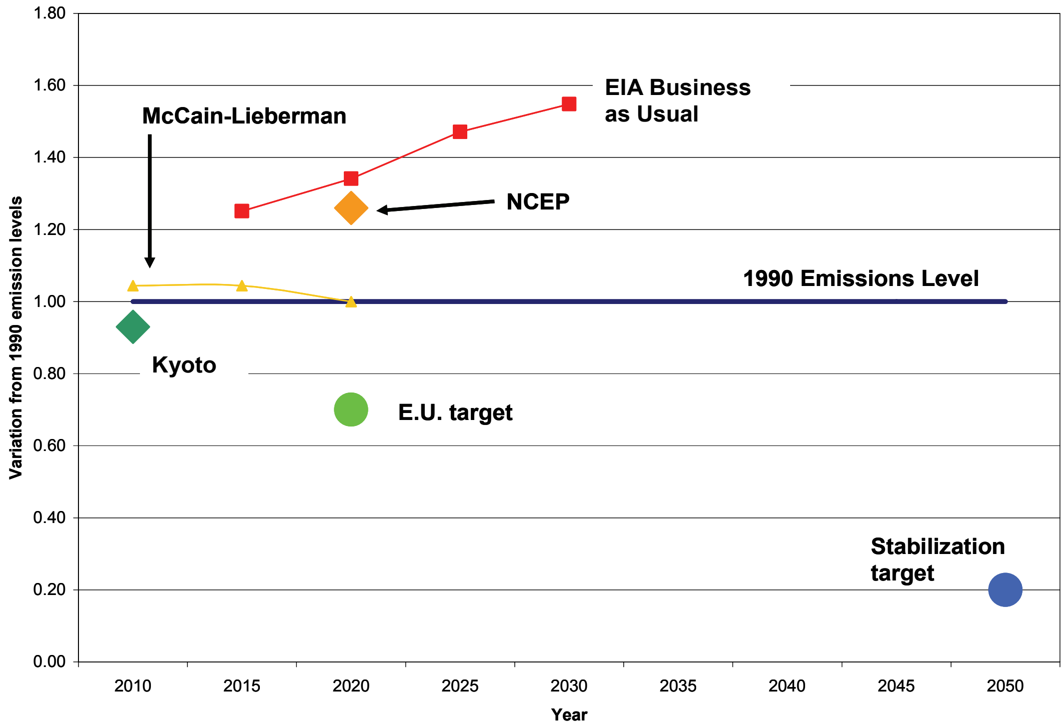

Figure 5.2 Comparison of Emission Reduction Goals

Figure compares emission reduction goals with 1990 as the baseline. Kyoto Protocol target for the United States would have been 7% below 1990 emissions levels. EU target is 20-30% below 1990 emissions levels. Stabilization target represents a reduction of 80% below 1990 levels. While there is no international agreement on the level at which emissions concentrations should be stabilized, and the emissions trajectory to achieve a stabilization target is not determined, reductions of 80% below 1990 levels indicates the magnitude of emissions reductions that are currently anticipated to be necessary.

As illustrated in the above figure, long term emission reduction goals are likely to be much more aggressive than those contained in federal policy proposals to date. Thus it is likely that cost projections will increase as targets become more stringent.

While efforts continue at the federal level, some individual states and regions are adopting their own greenhouse gas mitigation policies. Many corporations are also taking steps, on their own initiative, pursuant to state requirements, or under pressure from shareholder resolutions, in anticipation of mandates to reduce emissions of greenhouse gases. These efforts are described below.

5.2 State and regional policies

Many states across the country have not waited for federal policies and are developing and implementing climate change-related policies that have a direct bearing on resource choices in the electric sector. States, acting individually, and through regional coordination, have been the leaders on climate change policies in the United States. Generally, policies that individual states adopt fall into the following categories: (1) Direct policies that require specific emission reductions from electric generation sources; and (2) Indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (3) Legal proceedings; or (4) Voluntary programs including educational efforts and energy planning.

Table 5.2. Summary of Individual State Climate Change Policies

Type of Policy	Examples
Direct	
• Power plant emission restrictions (e.g. cap or emission rate)	• MA, NH
• New plant emission restrictions	• OR, WA
• State GHG reduction targets	• CT, NJ, ME, MA, CA, NM, NY, OR, WA
• Fuel/generation efficiency	• CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy)	
• Load-based GHG cap	• CA
• GHG in resource planning	• CA, WA, OR, MT, KY
• Renewable portfolio standards	• 22 states and D.C.
• Energy efficiency/renewable charges and funding; energy efficiency programs	• More than half the states
• Net metering, tax incentives	• 41 states
Lawsuits	
• States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act	• States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI
• States sue individual companies to reduce GHG emissions	• NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states have adopted direct policies that require specific emission reductions from specific electric sources. Some states have capped carbon dioxide emissions from sources in the state (through rulemaking or legislation), and some restrict emissions from new sources through offset requirements. The California Public Utilities Commission recently stated that it will develop a load-based cap on greenhouse gas emissions in the electric sector. Table 5.3 summarizes these direct policies.

Table 5.3. State Policies Requiring GHG Emission Reductions From Power Plants

Program type	State	Description	Date	Source
Emissions limit	MA	Department of Environmental Protection decision capping GHG emissions, requiring 10 percent reduction from historic baseline	April 1, 2001	310 C.M.R. 7.29
Emissions limit	NH	NH Clean Power Act	May 1, 2002	HB 284
Emissions limit on new plants	OR	Standard for CO_2 emissions from new electricity generating facilities (base-load gas, and non-base load generation)	Updated September 2003	OR Admin. Rules, Ch. 345, Div 24
Emissions limit on new plants	WA	Law requiring new power plants to mitigate emissions or pay for a portion of emissions	March 1, 2004	RCW 80.70.020
Load-based emissions limit	CA	Public Utilities Commission decision stating intent to establish load-based cap on GHG emissions	February 17, 2006	D. 06-02-032 in docket R. 04-04-003

Several states require that integrated utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement. Some of the states such as California require that companies use a specific value, while other states require generally that companies consider the risk of future regulation in their planning process. Table 5.4 summarizes state requirements for consideration of greenhouse gas emissions in the planning process.

Table 5.4. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

In June 2005 both California and New Mexico adopted ambitious greenhouse gas emission reduction targets that are consistent with current scientific understanding of the emissions reductions that are likely to be necessary to avoid dangerous human interference with the climate system. In California, an Executive Order directs the state to reduce GHG emissions to 2000 levels by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050. In New Mexico, an Executive Order established statewide goals to reduce New Mexico's total greenhouse gas emissions to 2000 levels by 2012, 10 percent below those levels by 2020, and 75 percent below 2000 levels by 2050. In September 2005 New Mexico also adopted a legally binding agreement to lower emissions through the Chicago Climate Exchange. More broadly, to date at least twenty-eight states have developed Climate Action Plans that include statewide plans for addressing climate change issues. Arizona and North Carolina are in the process of developing such plans.

States are also pursuing other approaches. For example, in November 2005, the governor of Pennsylvania announced a new program to modernize energy infrastructure through replacement of traditional coal technology with advanced coal gasification technology. Energy Deployment for a Growing Economy allows coal plant owners a limited time to continue to operate without updated emissions technology as long as they make a commitment by 2007 to replace older plants with IGCC by 2013.[40] In September of 2005 the North Carolina legislature formed a commission to study and make recommendations on voluntary GHG emissions controls. In October 2005, New Jersey designated carbon dioxide as a pollutant, a necessary step for the state's participation in the Regional Greenhouse Gas Initiative (described below).[41]

Finally, states are pursuing legal proceedings addressing greenhouse gas emissions. Many states have participated in one or several legal proceedings to seek greenhouse gas emission reductions from some of the largest polluting power plants. Some states have also sought a legal determination regarding regulation of greenhouse gases under the Clean Air Act. The most recent case involves 10 states and two cities suing the Environmental Protection Agency to determine whether greenhouse gases can be regulated under the Clean Air Act.[42] The states argue that EPA's recent emissions standards for new sources should include carbon dioxide since carbon dioxide, as a major contributor to global warming, harms public health and welfare, and thus falls within the scope of the Clean Air Act.

While much of the focus to date has been on the electric sector, states are also beginning to address greenhouse gas emissions in other sectors. For example, California has

[40] Press release, "Governor Rendell's New Initiative, 'The Pennsylvania EDGE,' Will Put Commonwealth's Energy Resources to Work to Grow Economy, Clean Environment," November 28, 2005.

[41] Press release, "Codey Takes Crucial Step to Combat Global Warming," October 18, 2005.

[42] The states are CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI. New York City and Washington D.C., as well as the Natural Resources Defense Council, the Sierra Club, and Environmental Defense. New York State Attorney General Eliot Spitzer, "States Sue EPA for Violating Clean Air Act and Failing to Act on Global Warming," press release, April 27, 2006.

adopted emissions standards for vehicles that would restrict carbon dioxide emissions. Ten other states have decided to adopt California's vehicle emissions standards.

States are not just acting individually; there are several examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g. Southwest governors, and Midwestern legislators) to development of a regional cap and trade program through the Regional Greenhouse Gas Initiative in the Northeast. These regional activities are summarized in Table 5.5, below.

Table 5.5. Regional Climate Change Policy Initiatives

Program type	State	Description	Date	Source
Regional GHG reduction Plan	CT, DE, MD, ME, NH, NJ, NY, VT	Regional Greenhouse Gas Initiative capping GHG emissions in the region and establishing trading program	MOU December 20, 2005, Model Rule February 2006	Memorandum of Understanding and Model Rule
Regional GHG reduction Plan	CA, OR, WA	West Coast Governors' Climate Change Initiative	September 2003, Staff report November 2004	Staff Report to the Governors
Regional GHG coordination	NM, AZ	Southwest Climate Change Initiative	February 28, 2006	Press release
Regional legislative coordination	IL, IA, MI, MN, OH, WI	Legislators from multiple states agree to coordinate regional initiatives limiting global warming pollution	February 7, 2006	Press release
Regional Climate Change Action Plan	New England, Eastern Canada	New England Governors and Eastern Canadian Premiers agreement for comprehensive regional Climate Change Action Plan. Targets are to reduce regional GHG emissions to 1990 levels by 2010, at least 10 percent below 1990 levels by 2020, and long-term reduction consistent with elimination of dangerous threat to climate (75-85 percent below current levels).	August, 2001	Memorandum of Understanding

Seven Northeastern and Mid-Atlantic states (CT, DE, ME, NH, NJ, NY, and VT) reached agreement in December 2005 on the creation of a regional greenhouse gas cap and trade program. The Regional Greenhouse Gas Initiative (RGGI) is a multi-year cooperative effort to design a regional cap and trade program initially covering CO_2 emissions from power plants in the region. Massachusetts and Rhode Island have actively participated in RGGI, but have not yet signed the agreement. Collectively, these states and Massachusetts and Rhode Island (which participated in RGGI negotiations) contribute 9.3 percent of total US CO_2 emissions and together rank as the fifth highest CO_2 emitter in the world. Maryland passed a law in April 2006 requiring participation in RGGI.[43] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process.[44]

The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes
- Certain offset provisions that increase flexibility to moderate price impacts
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.[45]

The states released a Model Rule in February 2006. The states must next consider adoption of rules consistent with the Model Rule through their regular legislative and regulatory policies and procedures.

Many cities and towns are also adopting climate change policies. Over 150 cities in the United States have adopted plans and initiatives to reduce emissions of greenhouse gases, setting emissions reduction targets and taking measures within municipal government operations. Climate change was a major issue at the annual US Conference of Mayors convention in June 2005, when the Conference voted unanimously to support a climate protection agreement, which commits cities to the goal of reducing emissions seven percent below 1990 levels by 2012.[46] World-wide, the Cities for Climate Protection Campaign (CCP), begun in 1993, is a global campaign to reduce emissions that cause climate change and air pollution. By 1999, the campaign had engaged more than 350 local governments in this effort, who jointly accounted for approximately seven percent of global greenhouse gas emissions.[47]All of these recent activities contribute to growing pressure within the United States to adopt regulations at a national level to reduce the emissions of greenhouse gases, particularly CO_2. This pressure is likely to increase over time as climate change issues and measures for addressing them become better

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[43] Maryland Senate Bill 154 *Healthy Air Act*, signed April 6, 2006.

[44] Information on this effort is available at www.rggi.org

[45] The MOU states "Each state will maintain and, where feasible, expand energy policies to decrease the use of less efficient or relatively higher polluting generation while maintaining economic growth. These may include such measures as: end-use efficiency programs, demand response programs, distributed generation policies, electricity rate designs, appliance efficiency standards and building codes. Also, each state will maintain and, where feasible, expand programs that encourage development of non-carbon emitting electric generation and related technologies." RGGI MOU, Section 7, December 20, 2005.

[46] the US Mayors Climate Protection Agreement, 2005. Information available at http://www.ci.seattle.wa.us/mayor/climate

[47] Information on the Cities for Climate Protection Campaign, including links to over 150 cities that have adopted greenhouse gas reduction measures, is available at http://www.iclei.org/projserv.htm#ccp

understood by the scientific community, by the public, the private sector, and particularly by elected officials.

5.3 Investor and corporate action

Several electric companies and other corporate leaders have supported the concept of a mandatory greenhouse gas emissions program in the United States. For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[48]

Similarly, in comments to the Senate Energy and Natural Resources Committee, the vice president of Exelon reiterated the company's support for a federal mandatory carbon policy, stating that "It is critical that we start now. We need the economic and regulatory certainty to invest in a low-carbon energy future."[49] Corporate leaders from other sectors are also increasingly recognizing climate change as a significant policy issue that will affect the economy and individual corporations. For example, leaders from Wal-Mart, GE, Shell, and BP, have all taken public positions supporting the development of mandatory climate change policies.[50]

In a 2004 national survey of electric generating companies in the United States, conducted by PA Consulting Group, about half the respondents believe that Congress will enact mandatory limits on CO_2 emissions within five years, while nearly 60 percent anticipate mandatory limits within the next 10 years. Respondents represented companies that generate roughly 30 percent of US electricity.[51] Similarly, in a 2005 survey of the North American electricity industry, 93% of respondents anticipate increased pressure to take action on global climate change.[52]

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[48] Paul Anderson, Chairman, Duke Energy, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," April 6, 2006 speech to CERES Annual Conference, at: http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf

[49] Elizabeth Moler, Exelon V.P., to the Senate Energy and Natural Resources Committee, April 4, 2006, quoted in Grist, http://www.grist.org/news/muck/2006/04/14/griscom-little/

[50] See, e.g., Raymond Bracy, V.P. for Corporate Affairs, Wal-Mart, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; David Slump, GE Energy, General Manager, Global Marketing, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; John Browne, CEO of BP, "Beyond Kyoto," Foreign Affairs, July/August 2004; Shell company website at www.shell.com.

[51] PA Consulting Group, "Environmental Survey 2004" Press release, October 22, 2004.

[52] GF Energy, "GF Energy 2005 Electricity Outlook" January 2005. However, it is interesting to note that climate ranked 11th among issues deemed important to individual companies.

Some investors and corporate leaders have taken steps to manage risk associated with climate change and carbon policy. Investors are gradually becoming aware of the financial risks associated with climate change, and there is a growing body of literature regarding the financial risks to electric companies and others associated with climate change. Many investors are now demanding that companies take seriously the risks associated with carbon emissions. Shareholders have filed a record number of global warming resolutions for 2005 for oil and gas companies, electric power producers, real estate firms, manufacturers, financial institutions, and auto makers.[53] The resolutions request financial risk disclosure and plans to reduce greenhouse gas emissions. Four electric utilities – AEP, Cinergy, TXU and Southern – have all released reports on climate risk following shareholder requests in 2004. In February 2006, four more US electric power companies in Missouri and Wisconsin also agreed to prepare climate risk reports.[54]

State and city treasurers, labor pension fund officials, and foundation leaders have formed the Investor Network on Climate Risk (INCR) which now includes investors controlling $3 trillion in assets. In 2005, the INCR issued "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," which discusses efforts to address climate risk since 2003 and identifies areas for further action. It urges institutional investors, fund managers, companies, and government policymakers to increase their oversight and scrutiny of the investment implications of climate change.[55] A 2004 report cites analysis indicating that carbon constraints affect market value – with modest greenhouse gas controls reducing the market capitalization of many coal-dependent US electric utilities by 5 to 10 percent, while a more stringent reduction target could reduce their market value 10 to 35 percent. [56] The report recommends, as one of the steps that company CEOs should pursue, integrating climate policy in strategic business planning to maximize opportunities and minimize risks.

Institutional investors have formed The Carbon Disclosure Project (CDP), which is a forum for institutional investors to collaborate on climate change issues. Its mission is to inform investors regarding the significant risks and opportunities presented by climate change; and to inform company management regarding the serious concerns of shareholders regarding the impact of these issues on company value. Involvement with the CDP tripled in about two and a half years, from $10 trillion under managements in

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[53] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[54] "Four Electric Power Companies in Midwest Agree to Disclose Climate Risk," CERES press release February 21, 2006. Companies are Great Plains Energy Inc. in Kansas City, MO, Alliant Energy in Madison, WI, WPS Resources in Green Bay, WI and MGE Energy in Madison, WI.

[55] 2005 Institutional Investor Summit, "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," May 10, 2005. The Final Report from the 2003 Institutional Investors Summit on Climate Risk, November 21, 2003 contains good summary information on risk associated with climate change.

[56] Cogan, Douglas G.; "Investor Guide to Climate Risk: Action Plan and Resource for Plan Sponsors, Fund Managers, and Corporations;" Investor Responsibility Research Center; July 2004 citing Frank Dixon and Martin Whittaker, "Valuing Corporate Environmental Performance: Innovest's Evaluation of the Electric Utilities Industry," New York, 1999.

Nov. 2003 to $31 trillion under management today.[57] The CDP released its third report in September 2005. This report continued the trend in the previous reports of increased participation in the survey, and demonstrated increasing awareness of climate change and of the business risks posed by climate change. CDP traces the escalation in scope and awareness – on behalf of both signatories and respondents – to an increased sense of urgency with respect to climate risk and carbon finance in the global business and investment community. [58]

Findings in the third CDP report included:

- More than 70% of FT500 companies responded to the CDP information request, a jump from 59% in CDP2 and 47% in CDP1.[59]
- More than 90% of the 354 responding FT500 companies flagged climate change as posing commercial risks and/or opportunities to their business.
- 86% reported allocating management responsibility for climate change.
- 80% disclosed emissions data.
- 63% of FT500 companies are taking steps to assess their climate risk and institute strategies to reduce greenhouse gas emissions.[60]

The fourth CDP information request (CDP4) was sent on behalf of 211 institutional investors with significant assets under management to the Chairmen of more than 1900 companies on February 1, 2006, including 300 of the largest electric utilities globally.

The California Public Employees' Retirement System (CalPERS) announced that it will use the influence made possible by its $183 billion portfolio to try to convince companies it invests in to release information on how they address climate change. The CalPERS board of trustees voted unanimously for the environmental initiative, which focuses on the auto and utility sectors in addition to promoting investment in firms with good environmental practices.[61]

Major financial institutions have also begun to incorporate climate change into their corporate policy. For example, Goldman Sachs and JP Morgan support mandatory market-based greenhouse gas reduction policies, and take greenhouse gas emissions into account in their financial analyses. Goldman Sachs was the first global investment bank to adopt a comprehensive environmental policy establishing company greenhouse gas

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[57] See: http://www.cdproject.net/aboutus.asp

[58] Innovest Strategic Value Advisors; "Climate Change and Shareholder Value In 2004," second report of the Carbon Disclosure Project; Innovest Strategic Value Advisors and the Carbon Disclosure Project; May 2004.

[59] FT 500 is the Financial Times' ranking of the top 500 companies ranked globally and by sector based on market capital.

[60] CDP press release, September 14, 2005. Information on the Carbon Disclosure Project, including reports, are available at: http://www.cdproject.net/index.asp.

[61] *Greenwire*, February 16, 2005

reduction targets and supporting a national policy to limit greenhouse gas emissions. [62] JP Morgan, Citigroup, and Bank of America have all adopted lending policies that cover a variety of project impacts including climate change.

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have taken steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints. Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013."[63] The President of Duke Energy urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[64] Prior to its merger with Duke, Cinergy Corporation was vocal on its support of mandatory national carbon regulation. Cinergy established a target is to produce 5 percent below 2000 levels by 2010 – 2012. AEP adopted a similar target. FPL Group and PSEG are both aiming to reduce total emissions by 18 percent between 2000 and 2008.[65] A fundamental impediment to action on the part of electric generating companies is the lack of clear, consistent, national guidelines so that companies could pursue emissions reductions without sacrificing competitiveness.

While statements such as these are an important first step, they are only a starting point, and do not, in and of themselves, cause reductions in carbon emissions. It is important to keep in mind the distinction between policy statements and actions consistent with those statements.

6. Anticipating the cost of reducing carbon emissions in the electric sector

Uncertainty about the form of future greenhouse gas reduction policies poses a planning challenge for generation-owning entities in the electric sector, including utilities and non-utility generators. Nevertheless, it is not reasonable or prudent to assume in resource planning that there is no cost or financial risk associated with carbon dioxide emissions, or with other greenhouse gas emissions. There is clear evidence of climate change, federal legislation has been under discussion for the past few years, state and regional regulatory efforts are currently underway, investors are increasingly pushing for companies to address climate change, and the electric sector is likely to constitute one of

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[62] Goldman Sachs Environmental Policy Framework, http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

[63] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[64] Paul M. Anderson Letter to Shareholders, March 15, 2005.

[65] Ibid.

the primary elements of any future regulatory plan. Analyses of various economy-wide policies indicate that a majority of emissions reductions will come from the electric sector. In this context and policy climate, utilities and non-utility generators must develop a reasoned assessment of the costs associated with expected emissions reductions requirements. Including this assessment in the evaluation of resource options enables companies to judge the robustness of a plan under a variety of potential circumstances.

This is particularly important in an industry where new capital stock usually has a lifetime of 50 or more years. An analysis of capital cycles in the electric sector finds that "external market conditions are the most significant influence on a firm's decision to invest in or decommission large pieces of physical capital stock.[66] Failure to adequately assess market conditions, including the potential cost increases associated with likely regulation, poses a significant investment risk for utilities. It would be imprudent for any company investing in plants in the electric sector, where capital costs are high and assets are long-lived, to ignore policies that are inevitable in the next five to twenty years. Likewise, it would be short-sighted for a regulatory entity to accept the valuation of carbon emissions at no cost.

Evidence suggests that a utility's overall compliance decisions will be more efficient if based on consideration of several pollutants at once, rather than addressing pollutants separately. For example, in a 1999 study EPA found that pollution control strategies to reduce emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury are highly inter-related, and that the costs of control strategies are highly interdependent.[67] The study found that the total costs of a coordinated set of actions is less than that of a piecemeal approach, that plant owners will adopt different control strategies if they are aware of multiple pollutant requirements, and that combined SO_2 and carbon emissions reduction options lead to further emissions reductions.[68] Similarly, in one of several studies on multi-pollutant strategies, the Energy Information Administration (EIA) found that using an integrated approach to NO_x, SO_2, and CO_2, is likely to lead to lower total costs than addressing pollutants one at a time.[69] While these studies clearly indicate that federal emissions policies should be comprehensive and address multiple pollutants, they also demonstrate the value of including future carbon costs in current resource planning activities.

There are a variety of sources of information that form a basis for developing a reasonable estimate of the cost of carbon emissions for utility planning purposes. Useful sources include recent market transactions in carbon markets, values that are currently being used in utility planning, and costs estimates based on scenario modeling of proposed federal legislation and the Regional Greenhouse Gas Initiative.

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[66] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[67] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[68] US EPA, *Briefing Report*, March 1999.

[69] EIA, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*. December 2000.

6.1 International market transactions

Implementation of the Kyoto Protocol has moved forward with great progress in recent years. Countries in the European Union (EU) are now trading carbon in the first international emissions market, the EU Emissions Trading Scheme (ETS), which officially launched on January 1, 2005. This market, however, was operating before that time – Shell and Nuon entered the first trade on the ETS in February 2003. Trading volumes increased steadily throughout 2004 and totaled approximately 8 million tons CO_2 in that year. [70]

Prices for current- and near-term EU allowances (2006-2007) escalated sharply in 2005, rising from roughly \$11/ton CO_2 (9 euros/ton-CO_2) in the second half of 2004 and leveling off at about \$36/ton CO_2 (28 euros/ton- CO_2) early in 2006. In March 2006, the market price for 2008 allowances hovered at around \$32/ton CO_2 (25 euros/ton- CO_2).[71] Lower prices in late April resulted from several countries' announcements that their emissions were lower than anticipated. The EU member states will submit their carbon emission allocation plans for the period 2008-2012 in June. Market activity to date in the EU Emissions trading system illustrates the difficulty of predicting carbon emissions costs, and the financial risk potentially associated with carbon emissions.

With the US decision not to ratify the Kyoto Protocol, US businesses are unable to participate in the international markets, and emissions reductions in the United States have no value in international markets. When the United States does adopt a mandatory greenhouse gas policy, the ability of US businesses and companies to participate in international carbon markets will be affected by the design of the mandatory program. For example, if the mandatory program in the United States includes a safety valve price, it may restrict participation in international markets.[72]

6.2 Values used in electric resource planning

Several companies in the electric sector evaluate the costs and risks associated with carbon emissions in resource planning. Some of them do so at their own initiative, as part of prudent business management, others do so in compliance with state law or regulation.

Some states require companies under their jurisdiction to account for costs and/or risks associated with regulation of greenhouse gas emissions in resource planning. These states include California, Oregon, Washington, Montana, Kentucky (through staff reports), and Utah. Other states, such as Vermont, require that companies take into account environmental costs generally. The Northwest Power and Conservation Council

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[70] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[71] These prices are from Evolution Express trade data, http://www.evomarkets.com/, accessed on 3/31/06.

[72] See, e.g. Pershing, Jonathan, Comments in Response to Bingaman-Domenici Climate Change White Paper, March 13, 2006. Sandalow, David, Comments in Response to Bingaman-Domenici Climate Change White Paper, The Brookings Institution, March 13, 2006.

includes various carbon scenarios in its Fifth Power Plan. For more information on these requirements, see the section above on state policies.[73]

California has one of the most specific requirements for valuation of carbon in integrated resource planning. The California Public Utilities Commission (PUC) requires companies to include a carbon adder in long-term resource procurement plans. The Commission's decision requires the state's largest electric utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) to factor the financial risk associated with greenhouse gas emissions into new long-term power plant investments, and long-term resource plans. The Commission initially directed utilities to include a value between \$8–25/ton CO_2 in their submissions, and to justify their selection of a number.[74] In April 2005, the Commission adopted, for use in resource planning and bid evaluation, a CO_2 adder of \$8 per ton of CO_2 in 2004, escalating at 5% per year.[75] The Montana Public Service Commission specifically directed Northwest Energy to evaluate the risks associated with greenhouse gas emissions in its 2005 Integrated Resource Plan (IRP).[76] In 2006 the Oregon Public Utilities Commission (PUC) will be investigating its long-range planning requirements, and will consider whether a specific carbon adder should be required in the base case (Docket UM 1056).

Several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs in their long term planning, and have set specific agendas to mitigate shareholder risks associated with future US carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the US electric sector emissions contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[77] Table 6.1 illustrates the range of carbon cost values, in \$/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

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[73] For a discussion of the use of carbon values in integrated resource planning see, Wiser, Ryan, and Bolinger, Mark; *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans;* Lawrence Berkeley National Laboratories; August 2005. LBNL-58450

[74] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

[75] California Public Utilities Commission, Decision 05-04-024, April 2005.

[76] Montana Public Service Commission, "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229," August 17, 2004.

[77] Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

Table 6.1 CO_2 Costs in Long Term Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

These early efforts by utilities have brought consideration of the risks associated with future carbon regulations into the mainstream in resource planning the electric sector.

6.3 Analyses of carbon emissions reduction costs

With the emergence of federal policy proposals in the United States in the past several years, there have been several policy analyses that project the cost of carbon-dioxide equivalent emission allowances under different policy designs. These studies reveal a range of cost estimates. While it is not possible to pinpoint emissions reduction costs given current uncertainties about the goal and design of carbon regulation as well as the inherent uncertainties in any forecast, the studies provide a useful source of information for inclusion in resource decisions. In addition to establishing ranges of cost estimates, the studies give a sense of which factors affect future costs of reducing carbon emissions.

There have been several studies of proposed federal cap and trade programs in the United States. Table 6.2 identifies some of the major recent studies of carbon policy proposals.

Table 6.2. Analyses of US Carbon Policy Proposals

Policy proposal	Analysis
McCain Lieberman – S. 139	EIA 2003, MIT 2003, Tellus 2003
McCain Lieberman – SA 2028	EIA 2004, MIT 2003, Tellus 2004
Greenhouse Gas Intensity Targets	EIA 2005, EIA 2006
Jeffords – S. 150	EPA 2005
Carper 4-P – S. 843	EIA 2003, EPA 2005

Both versions of the McCain and Lieberman proposal (also known as the Climate Stewardship Act) were the subject of analyses by EIA, MIT, and the Tellus Institute. As originally proposed, the McCain Lieberman legislation capped 2010 emissions at 2000 levels, with a reduction in 2016 to 1990 levels. As revised, McCain Lieberman just included the initial cap at 2000 levels without a further restriction. In its analyses, EIA ran several sensitivity cases exploring the impact of technological innovation, gas prices, allowance auction, and flexibility mechanisms (banking and international offsets). [78]

In 2003 researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation.[79] MIT held emissions for 2010 and beyond at 2000 levels (not modeling the second step of the proposed legislation). Due to constraints of the model, the MIT group studied an economy-wide emissions limit rather than a limit on the energy sector. A first set of scenarios considers the cap tightening in Phase II and banking. A second set of scenarios examines the possible effects of outside credits. And a final set examines the effects of different assumptions about baseline gross domestic product (GDP) and emissions growth.

The Tellus Institute conducted two studies for the Natural Resources Defense Council of the McCain Lieberman proposals (July 2003 and June 2004).[80] In its analysis of the first proposal (S. 139), Tellus relied on a modified version of the National Energy Modeling System that used more optimistic assumptions for energy efficiency and renewable energy technologies based on expert input from colleagues at the ACEEE, the Union of Concerned Scientists, the National Laboratories and elsewhere. Tellus then modeled two policy cases. The "Policy Case" scenario included the provisions of the Climate Stewardship Act (S.139) as well as oil savings measures, a national renewable transportation fuel standard, a national RPS, and emissions standards contained in the Clean Air Planning Act. The "Advanced Policy Case" included the same complimentary energy policies as the "Policy Case" and assumed additional oil savings in the

[78] Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, EIA June 2003, SR/OIAF/2003-02; Energy Information Administration, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, EIA May 2004, SR/OIAF/2004-06

[79] Paltsev, Sergei; Reilly, John M.; Jacoby, Henry D.; Ellerman, A. Denny; Tay, Kok Hou; *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal.* MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

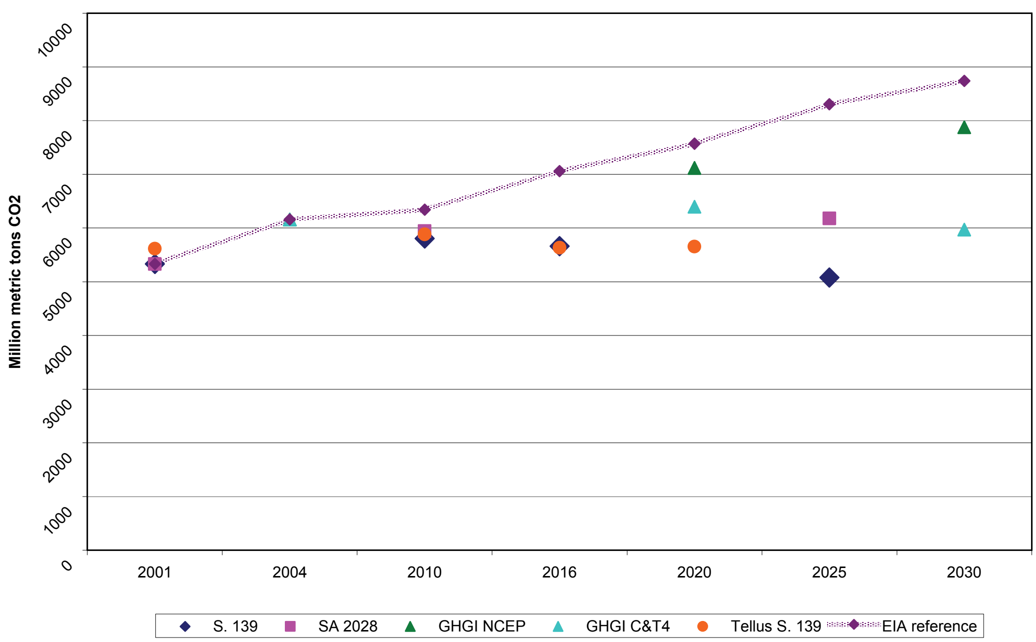
[80] Bailie et al., *Analysis of the Climate Stewardship Act,* July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ) (25 mpg in 2005, increasing to 45 mpg in 2025).

EIA has also analyzed the effect and cost of greenhouse gas intensity targets as proposed by Senator Bingaman based on the National Commission on Energy Policy, as well as more stringent intensity targets.[81] Some of the scenarios included safety valve prices, and some did not.

In addition to the analysis of economy-wide policy proposals, proposals for GHG emissions restrictions have also been analyzed. Both EIA and the U.S. Environmental Protection Agency (EPA) analyzed the four-pollutant policy proposed by Senator Carper (S. 843).[82] EPA also analyzed the power sector proposal from Senator Jeffords (S. 150).[83]

Figure 6.1 shows the emissions trajectories that the analyses of economy-wide policies projected for specific policy proposals. The graph does not include projections for policies that would just apply to the electric sector since those are not directly comparable to economy-wide emissions trajectories.



[81] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,* March 2006. SR/OIAF/2006-01.

[82] EIA. Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003. EIA Office of Integrated Analysis and Forecasting. SR/OIAF/2003-03. September 2003. US EPA, *Multi-pollutant Legislative Analysis: The Clean Power Act (Jeffords, S. 150 in the 109th)*. US EPA Office of Air and Radiation, October 2005.

[83] US Environmental Protection Agency, *Multi-pollutant Legislative Analysis: The Clean Air Planning Act (Carper, S. 843 in the 108th)*. US EPA Office of Air and Radiation, October 2005.

Figure 6.1. Projected Emissions Trajectories for US Economy-wide Carbon Policy Proposals.

Projected emissions trajectories from EIA and Tellus Institute Analyses of US economy-wide carbon policies. Emissions projections are for "affected sources" under proposed legislation. S. 139 is the EIA analysis of McCain Lieberman Climate Stewardship Act from 2003, SA 2028 is the EIA analysis of McCain Lieberman Climate Stewardship Act as amended in 2005. GHGI NCEP is the EIA analysis of greenhouse gas intensity targets recommended by the National Commission on Energy Policy and endorsed by Senators Bingaman and Domenici, GHGIC&T4 is the most stringent emission reduction target modeled by EIA in its 2006 analysis of greenhouse gas intensity targets, and Tellus S.139 is from the Tellus Institute analysis of S. 139.

Figure 6.2 presents projected carbon allowance costs from the economy-wide and electric sector studies in constant 2005 dollars per ton of carbon dioxide.

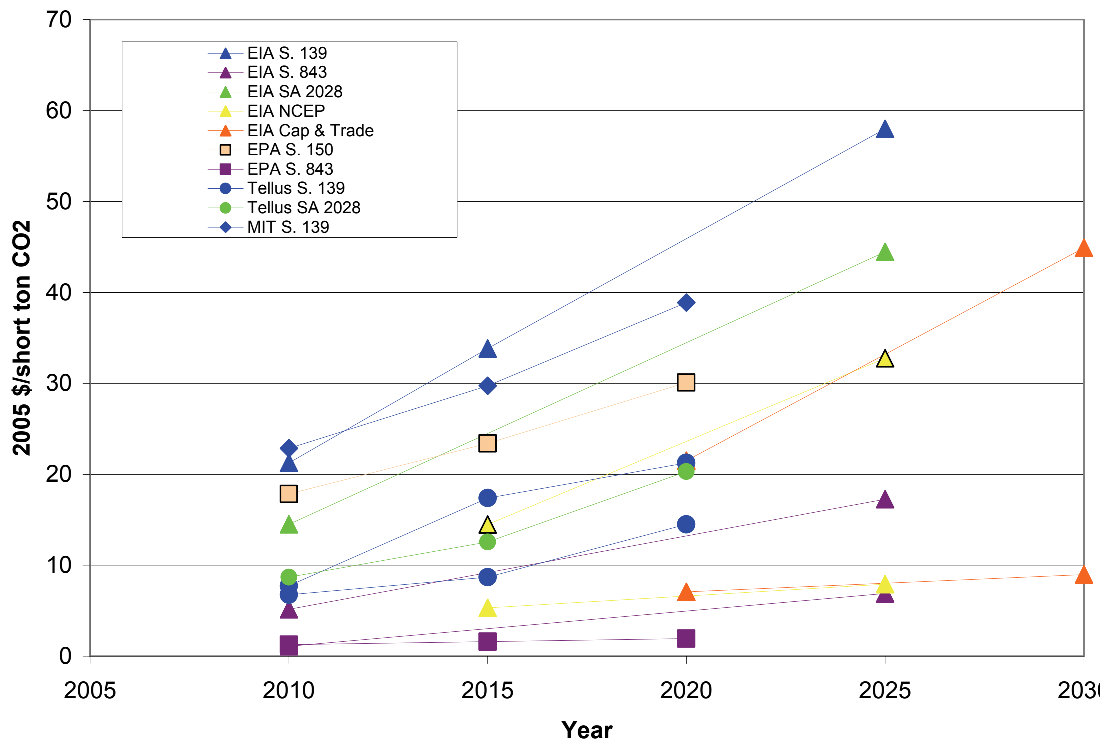


Figure 6.2. Allowance Cost Estimates From Studies of Economy-wide and Electric Sector US Policy Proposals

Carbon emissions price forecasts based on a range of proposed federal carbon regulations. Sources of data include: Triangles – US Energy Information Agency (EIA); Square – US EPA; Circles – Tellus Institute; Diamond – MIT. All values shown have been converted into 2005 dollars per short ton CO2 equivalent. Color-coded policies evaluated include:

Blue: *S. 139, the McCain-Lieberman Climate Stewardship Act of January 2003. MIT Scenario includes banking and zero-cost credits (effectively relaxing the cap by 15% and 10% in phase I and II, respectively.) The Tellus scenarios are the "Policy" case (higher values) and the "Advanced" case (lower values). Both Tellus cases include complimentary emission reduction policies, with "advance" policy case assuming additional oil savings in the transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ).*

Tan: *S.150, the Clean Power Act of 2005*

Violet: *S. 843, the Clean Air Planning Act of 2003. Includes international trading of offsets. EIA data include "High Offsets"(lower prices) and "Mid Offsets" (higher prices) cases. EPA data shows effect of tremendous offset flexibility.*

Bright Green: *SA 2028, the McCain-Lieberman Climate Stewardship Act Amendment of October 2003. This version sets the emissions cap at constant 2000 levels and allows for 15% of the carbon reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources.*

Yellow: *EIA analysis of the National Commission on Energy Policy (NCEP) policy option recommendations. Lower series has a safety-valve maximum permit price of $6.10 per metric ton CO2 in 2010 rising to $8.50 per metric ton CO2 in 2025, in 2003 dollars. Higher series has no safety value price. Both include a range of complementary policies recommended by NCEP.*

Orange: *EIA analysis of cap and trade policies based on NCEP, but varying the carbon intensity reduction goals. Lower-priced series (Cap and trade 1) has an intensity reduction of 2.4%/yr from 2010 to 2020 and 2.8%/yr from 2020 to 2030; safety-valve prices are $6.16 in 2010, rising to $9.86 in 2030, in 2004 dollars. Higher-priced series (Cap and trade 4) has intensity reductions of 3% per year and 4% per year for 2010-2020 and 2020-2030, respectively, and safety-valve prices of $30.92 in 2010 rising to $49.47 in 2030, in 2004 dollars.*

The lowest allowance cost results (EPA S. 843, EIA NCEP, and EIA Cap & Trade) correspond to the EPA analysis of a power sector program with very extensive offset use, and to EIA analyses of greenhouse gas intensity targets with allowance safety valve prices. In these analyses, the identified emission reduction target is not achieved because the safety valve is triggered. In EIA GHGI C&T 4, the price is higher because the greenhouse gas intensity target is more stringent, and there is no safety valve. The EIA analysis of S. 843 shows higher cost projections because of the treatment of offsets, which clearly cause a huge range in the projections for this policy. In the EPA analysis, virtually all compliance is from offsets from sources outside of the power sector.

In addition to its recent modeling of US policy proposals, EIA has performed several studies projecting costs associated with compliance with the Kyoto Protocol. In 1998, EIA performed a study analyzing allowance costs associated with six scenarios ranging from emissions in 2010 at 24 percent above 1990 emissions levels, to emissions in 2010 at 7 percent below 1990 emissions levels.[84] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the

[84] EIA, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

original study.[85] Carbon dioxide costs projected in these EIA studies of Kyoto targets were generally higher than those projected in the studies of economy-wide legislative proposals due in part to the more stringent emission reduction requirements of the Kyoto Protocol. For example, carbon dioxide allowances for 2010 were projected at $91 per short ton CO_2 ($2005) and $100 per short ton CO_2 ($2005) respectively for targets of seven percent below 1990 emissions levels. While the United States has not ratified the Kyoto Protocol, these studies are informative since they evaluate more stringent emission reduction requirements than those contained in current federal policy proposals. Scientists anticipate that avoiding dangerous climate change will require even steeper reductions than those in the Kyoto Protocol.

The State Working Group of the RGGI in the Northeast engaged ICF Consulting to analyze the impacts of implementing a CO2 cap on the electric sector in the northeastern states. ICF used the IPM model to analyze the program package that the RGGI states ultimately agreed to. ICF's analysis results (in $2004) range from $1-$5/ton CO_2 in 2009 to about $2.50-$12/ton CO_2 in 2024.[86] The lowest CO2 allowance prices are associated with the RGGI program package under the expected emission growth scenario. The costs increase significantly under a high emissions scenario, and increase even more when the high emissions scenario is combined with a national cap and trade program due to the greater demand for allowances in a national program. ICF performed some analysis that included aggressive energy efficiency scenarios and found that those energy efficiency components would reduce the costs of the RGGI program significantly.

In 2003 ICF was retained by the state of Connecticut to model a carbon cap across the 10 northeastern states. The cap is set at 1990 levels in 2010, 5 percent below 1990 levels in 2015, and 10 percent below 1990 levels in 2020. The use of offsets is phased in with entities able to offset 5 percent or their emissions in 2015 and 10 percent in 2020. The CO_2 allowance price, in $US2004, for the 10-state region increases over the forecast period in the policy case, rising from $7/ton in 2010 to $11/ton in 2020.[87]

6.4 Factors that affect projections of carbon cost

Results from a range of studies highlight certain factors that affect projections of future carbon emissions prices. In particular, the studies provide insight into whether the factors increase or decrease expected costs, and to the relationships among different factors. A number of the key assumptions that affect policy cost projections (and indeed policy costs) are discussed in this section, and summarized in Table 6.3.

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[85] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol," July 1999. SR/OIAF/99-02.

[86] ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

[87] Center for Clean Air Policy, *Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee*, January 2004, p. 3.3-27.

Here we only consider these factors in a qualitative sense, although quantitative meta-analyses do exist.[88] It is important to keep these factors in mind when attempting to compare and survey the range of cost/benefit studies for carbon emissions policies so the varying forecasts can be kept in the proper perspective.

Base case emissions forecast

Developing a business-as-usual case (in the absence of federal carbon emission regulations) is a complex modeling exercise in itself, requiring a wide range of assumptions and projections which are themselves subject to uncertainty. In addition to the question of future economic growth, assumptions must be made about the emissions intensity of that growth. Will growth be primarily in the service sector or in industry? Will technological improvements throughout the economy decrease the carbon emissions per unit of output?

In addition, a significant open question is the future generation mix in the United States. Throughout the 1990s most new generating investments were in natural gas-fired units, which emit much less carbon per unit of output than other fossil fuel sources. Today many utilities are looking at baseload coal due to the increased cost of natural gas, implying much higher emissions per MWh output. Some analysts predict a comeback for nuclear energy, which despite its high cost and unsolved waste disposal and safety issues has extremely low carbon emissions.

A business-as-usual case which included several decades of conventional base load coal, combined with rapid economic expansion, would present an extremely high emissions baseline. This would lead to an elevated projected cost of emissions reduction regardless of the assumed policy mechanism.

Complimentary policies

Complimentary energy policies, such as direct investments in energy efficiency, are a very effective way to reduce the demand for emissions allowances and thereby to lower their market price. A policy scenario which includes aggressive energy efficiency along with carbon emissions limits will result in lower allowances prices than one in which energy efficiency is not directly addressed.[89]

Policy implementation timeline and reduction target

Most "policy" scenarios are structured according to a goal such as achieving "1990 emissions by 2010" meaning that emissions should be decreased to a level in 2010 which

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[88] See, *e.g.*, Carolyn Fischer and Richard D. Morgenstern, *Carbon Abatement Costs: Why the Wide Range of Estimates?* Resources for the Future, September, 2003. http://www.rff.org/Documents/RFF-DP-03-42.pdf

[89] A recent analysis by ACEEE demonstrates the effect of energy efficiency investments in reducing the projected costs of the Regional Greenhouse Gas Initiative. Prindle, Shipley, and Elliott; *Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative*; American Council for an Energy Efficient Economy, May 2006. Report Number E064.

is no higher than they were in 1990. Both of these policy parameters have strong implications for policy costs, although not necessarily in the intuitive sense. A later implementation date means that there is more time for the electric generating industry to develop and install mitigation technology, but it also means that if they wait to act, they will have to make much more drastic cuts in a short period of time. Models which assume phased-in targets, forcing industry to take early action, may stimulate technological innovations so that later, more aggressive targets can be reached at lower cost.

Program flexibility

The philosophy behind cap and trade regulation is that the rules should specify an overall emissions goal, but the market should find the most efficient way of meeting that goal. For emissions with broad impacts (as opposed to local health impacts) this approach will work best at minimizing cost if maximum flexibility is built into the system. For example, trading should be allowed across as broad as possible a geographical region, so that regions with lower mitigation cost will maximize their mitigation and sell their emission allowances. This need not be restricted to CO_2 but can include other GHGs on an equivalent basis, and indeed can potentially include trading for offsets which reduce atmospheric CO_2 such as reforestation projects. Another form of flexibility is to allow utilities to put emissions allowances "in the bank" to be used at a time when they hold higher value, or to allow international trading as is done in Europe through the Kyoto protocol.

One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. [90] Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable."[91] Still, there is a clear benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume higher flexibility in all of these areas are likely to predict lower compliance costs for reaching any specified goal.

Technological progress

The rate of improvement in mitigation technology is a crucial assumption in predicting future emissions control costs. This has been an important factor in every major air emissions law, and has resulted, for example, in the pronounced downward trend in allowance prices for SO_2 and NO_x in the years since regulations of those two pollutants were enacted. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in carbon-free generation

[90] An additional consideration is that greater geographic flexibility reduces potential local co-benefits, discussed below, that can derive from efforts to reduce greenhouse gas emissions.

[91] Massachusetts 310 CMR 7.29.

technologies. Improvements in the efficiency of coal burning technology or in the cost of nuclear power plants may also be a factor.

Reduced emissions co-benefits

Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2 and mercury. This results in cost savings not only to the generators who no longer need these permits, but also to broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

Table 6.3. Factors That Affect Future Carbon Emissions Policy Costs

Assumption	Increases Prices if…	Decreases Prices if…
• **"Base case" emissions forecast**	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual" emissions
• **Complimentary policies**	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
• **Policy implementation timeline**	Delayed and/or sudden program implementation	Early action, phased-in emissions limits.
• **Reduction targets**	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
• **Program flexibility**	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects.
• **Technological progress**	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions
• **Emissions co-benefits**	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants.

Because of the uncertainties and interrelationships surrounding these factors, forecasting long-range carbon emissions price trajectories is quite complicated and involves significant uncertainty. Of course, this uncertainty is no greater than the uncertainty surrounding other key variables underlying future electricity costs, such as fuel prices, although there are certain characteristics that make carbon emissions price forecasting unique.

One of these is that the forecaster must predict the future political climate. As documented throughout this paper, recent years have seen a dramatic increase in both the documented effects of and the public awareness of global climate change. As these trends continue, it is likely that more aggressive and more expensive emissions policies will be politically feasible. Political events in other areas of the world may be another factor, in that it will be easier to justify aggressive policies in the United States if other nations such as China are also limiting emissions.

Another important consideration is the relationship between early investments and later emissions costs. It is likely that policies which produce high prices early will greatly accelerate technological innovation, which could lead to prices in the following decades which are lower than they would otherwise be. This effect has clearly played a role in NO_x and SO_2 allowance trading prices. However, the effect would be offset to some degree by the tendency for emissions limits to become more restrictive over time, especially if mitigation becomes less costly and the effects of global climate change become increasingly obvious.

6.5 Synapse forecast of carbon dioxide allowance prices

Below we offer an emissions price forecast which the authors judge to represent a reasonable range of likely future CO_2 allowance prices. Because of the factors discussed above and others, it is likely that the actual cost of emissions will not follow a smooth path like those shown here but will exhibit swings between and even outside of our "low" and "high" cases in response to political, technological, market and other factors. Nonetheless, we believe that these represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation.

Figure 6.3 shows our price forecasts for the period 2010 through 2030, superimposed upon projections collected from other studies mentioned in this paper.

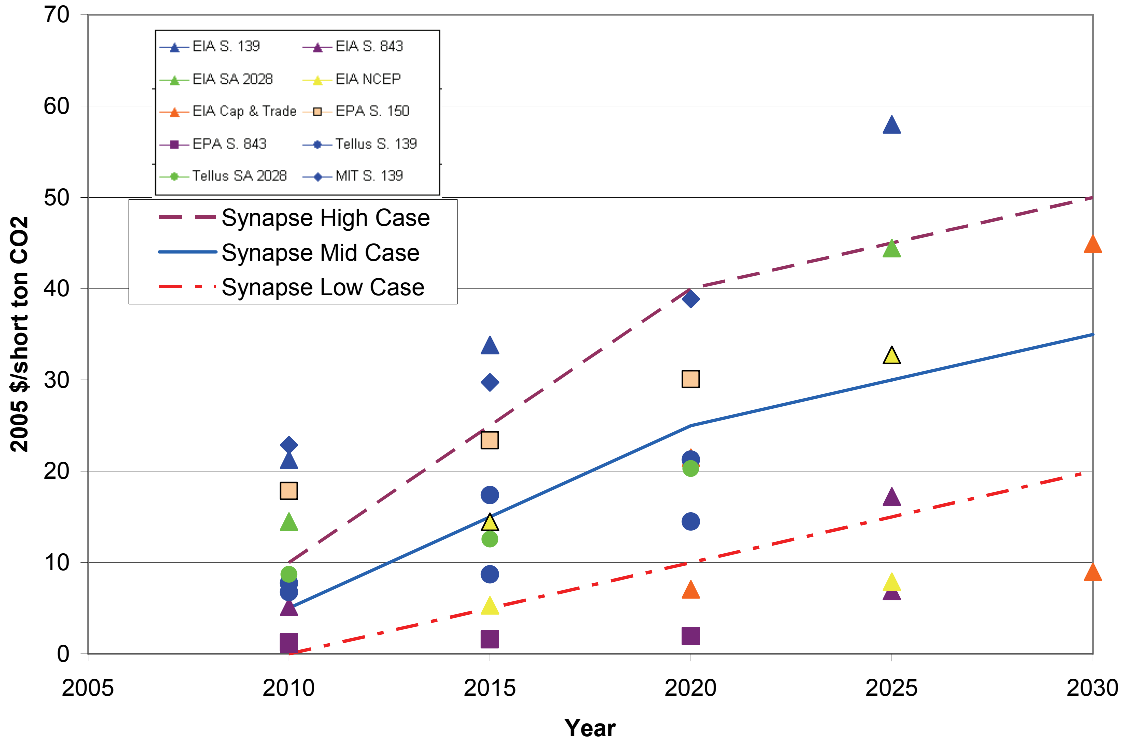

Figure 6.3. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon dioxide emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.2.

In developing our forecast we have reviewed the cost analyses of federal proposals, the Kyoto Protocol, and current electric company use of carbon values in IRP processes, as described earlier in this paper. The highest cost projections from studies of U.S. policy proposals generally reflect a combination of factors including more aggressive emissions reductions, conservative assumptions about complimentary energy policies, and limited or no offsets. For example, some of the highest results come from EIA analysis of the most aggressive emission reductions proposed -- the Climate Stewardship Act, as originally proposed by Senators McCain and Lieberman in 2003. Similarly, the highest cost projection for 2025 is from the EPA analysis of the Carper 4-P bill, S. 843, in a scenario with fairly restricted offset use. The lowest cost projections are from the analysis of the greenhouse gas intensity goal with a safety valve, as proposed by the National Commission on Energy Policy, as well as from an EPA analysis of the Carper 4-P bill, S. 843, with no restrictions on offset use. These highest and lowest cost estimates illustrate the effect of the factors that affect projections of CO_2 emissions costs, as discussed in the previous section.

We believe that the U.S. policies that have been modeled can reasonably be considered to represent the range of U.S. policies that could be adopted in the next several years. However, we do not anticipate the adoption of either the most aggressive or restrictive, or the most lenient and flexible policies illustrated in the range of projections from recent analyses. Thus we consider both the highest and the lowest cost projections from those studies to be outside of our reasonable forecast.

We note that EIA projections of costs to comply with Kyoto Protocol targets were much higher, in the range of \$100/ton CO_2. The higher cost projections associated with the Kyoto Protocol targets, which are somewhat more aggressive than U.S. policy proposals, are consistent with the anticipated effect of a more carbon-constrained future. The EIA analysis also has pessimistic assumptions regarding carbon emission-reducing technologies and complementary policies. The range of values that certain electric companies currently use in their resource planning and evaluation processes largely fall within the high and low cost projections from policy studies. Our forecast of carbon dioxide allowance prices is presented in Table 6.4.

Table 6.4. Synapse forecast of carbon dioxide allowance prices (\$2005/ton CO_2).

	2010	2020	2030	Levelized Value 2011-2030
Synapse Low Case	0	10	20	8.23
Synapse Mid Case	5	25	35	19.83
Synapse High Case	10	40	50	31.43

As illustrated in the table, we have identified what we believe to be a reasonable high, low, and mid case for three time periods: 2010, 2020, and 2030. These high, low, and mid case values for the years in question represent a range of values that are reasonably plausible for use in resource planning. Certainly other price trajectories are possible, indeed likely depending on factors such as level of reduction target, and year of implementation of a policy. We have much greater confidence in the levelized values over the period than we do in any particular annual values or in the specific shape of the price projections.

Using these value ranges, we have plotted cost lines in Figure 6.3 for use in resource analysis. In selecting these values, we have taken into account a variety of factors for the three time periods. While some regions and states may impose carbon emissions costs sooner, or federal legislation may be adopted sooner, our assumption conservatively assumes that implementation of any federal legislative requirements is unlikely before 2010. We project a cost in 2010 of between zero and \$10 per ton of CO_2.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices reflects the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). Thus we find the widest uncertainty in our forecasts begins at the end of this decade from \$10 to \$40 per ton of CO_2, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward the marginal mitigation cost of carbon emissions. This number still depends on uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that the least expensive mitigation options (such as simple energy efficiency and fuel switching) will be exhausted. Our projection for the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

We think the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, making the most likely scenario closer to (though not equal to) low case scenarios than the high case scenario. The probability of taking this path increases over time, as society learns more about optimal carbon reduction policies.

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices increases due to interplay of factors such as the level of carbon constraints required, and technological innovation. As discussed in previous sections, scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though the cost of such deeper cuts has not been quantified on a per ton basis.

On the other hand, we also anticipate a reasonable likelihood that increasing concern over climate change impacts, and the accompanying push for more aggressive emission reductions, will drive technological innovation, which may be anticipated to prevent unlimited cost escalation. For example, with continued technology improvement, coupled with attainment of economies of scale, significant price declines in distributed generation, grid management, and storage technologies, are likely to occur. The combination of such price declines and carbon prices could enable tapping very large supplies of distributed resources, such as solar, low-speed wind and bioenergy resources, as well as the development of new energy efficiency options. The potential development of carbon sequestration strategies, and/or the transition to a renewable energy-based economy may also mitigate continued carbon price escalation.

7. Conclusion

The earth's climate is strongly influenced by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in the Third Assessment Report of the Intergovernmental Panel on Climate Change and in countless peer-reviewed scientific studies and reports, is that the climate system is already being – and will continue to be – disrupted due to anthropogenic emissions of greenhouse gases. Scientists expect increasing atmospheric concentrations of greenhouse gases to cause temperature increases of 1.4 – 5.8 degrees centigrade by 2100, the fastest rate of change since end of the last ice age. Such global warming is expected to cause a wide range of climate impacts including changes in precipitation patterns, increased climate variability, melting of glaciers, ice shelves and permafrost, and rising sea levels. Some of these changes have already been observed and documented in a growing body of scientific literature. All countries will experience social and economic consequences, with disproportionate negative impacts on those countries least able to adapt.

The prospect of global warming and changing climate has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions by industrialized nations and by economies in transition.

The United States, which is the single largest contributor to global emissions of greenhouse gases, remains one of a very few industrialized nations that have not signed onto the Kyoto Protocol. Nevertheless, federal legislation seems likely in the next few years, and individual states, regional organizations, corporate shareholders and corporations themselves are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon emissions, though not yet successful, have gained ground in recent years. And climate change issues have seen an unprecedented level of attention in the United States at all levels of government in the past few years.

These developments, combined with the growing scientific certainty related to climate change, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how, and how much additional damage will have been incurred by the process of delay. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector’s contribution to national emissions and the comparative ease of controlling emissions from large point sources. While the future costs of compliance are subject to uncertainty, they are real and will be mandatory within the lifetime of electric industry capital stock being planned for and built today.

In this scientific, policy and economic context, it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. Failure to consider the potential future costs of greenhouse gas emissions under future mandatory emission reductions will result in investments that prove quite uneconomic in the future. Long term resource planning by utility and non-utility owners of electric generation must account for the cost of mitigating greenhouse gas emissions, particularly carbon dioxide. For example, decisions about a company’s resource portfolio, including building new power plants, reducing other pollutants or installing pollution controls, avoided costs for efficiency or renewables, and retirement of existing power plants all can be more sophisticated and more efficient with appropriate consideration of future costs of carbon emissions mitigation.

Regulatory uncertainty associated with climate change clearly presents a planning challenge, but this does not justify proceeding as if no costs will be associated with carbon emissions in the future. The challenge, as with any unknown future cost driver, is to forecast a reasonable range of costs based on analysis of the information available. This report identifies many sources of information that can form the basis of reasonable assumptions about the likely costs of meeting future carbon emissions reduction requirements.

Additional Costs Associated with Greenhouse Gases

It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

Incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates. However, current policy proposals are just a first step in the direction of emissions reductions that are likely to ultimately be necessary. Consequently, electric sector participants should anticipate increasingly stringent regulatory requirements. In addition, anticipating the financial risks associated with greenhouse gas regulation does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

This report is unchanged from the August 31, 2006 version except for the correction of a graphical error.

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Joint Intervenors
Exhibit 1

BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application by Otter Tail Power Company on behalf of the Big Stone II Co-owners for an Energy Conversion Facility Siting Permit for the Construction of the Big Stone II Project	))))	**Case No EL05-022**

Direct Testimony of
David A. Schlissel and Anna Sommer
Synapse Energy Economics, Inc.

On Behalf of
Minnesotans for an Energy-Efficient Economy
Izaak Walton League of America – Midwest Office
Union of Concerned Scientists
Minnesota Center for Environmental Advocacy

May 19, 2006

Joint Intervenors
Exhibit 1

List of Joint Intervenors Exhibits

JI-1-A	Resume of David Schlissel
JI-1-B	Resume of Anna Sommer
JI-1-C	EIA Natural Gas Price Forecasts 1990-2006
JI-1-D	Interrogatory 18 of Joint Intervenors' First Set and First Amended Set of Interrogatories
JI-1-E	Descriptive Slide Submitted to Commission by Co-owners on 10.5.2005
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JI-1-H	Joint Intervenors' First Set of Requests for Admission

Q. Mr. Schlissel, please state your name, position and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Ms. Sommer, please state your name position and business address.

A. My name is Anna Sommer. I am a Research Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, MA 02139.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of Minnesotans for an Energy-Efficient Economy, Izaak Walton League of America – Midwest Office, Union of Concerned Scientists, and Minnesota Center for Environmental Advocacy ("Joint Intervenors").

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff (and have included the Staff of the South Dakota Public Utilities Commission), attorneys general, environmental organizations, federal government and utilities.

Q. Mr. Schlissel, please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the Arizona Corporation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Kansas State Corporation Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit JI-1-A.

Q. Have you previously submitted testimony before this Commission?

A. No.

Q. Ms. Sommer, please summarize your educational background and work experience.

A. I am a Research Associate with Synapse Energy Economics. I provide research and assist in writing testimony and reports on a wide range of issues from renewable energy policy to integrated resource planning. My recent work includes aiding a Florida utility in its integrated resource planning, evaluating the feasibility of carbon sequestration and reviewing the analyses of the air emissions compliance plans of two Indiana utilities and one Nova Scotia utility.

I also have participated in studies of proposed renewable portfolio standards in the United States and Canada. In addition, I have evaluated the equity of utility renewable energy solicitations in Nova Scotia and the feasibility and prudence of the sale and purchase of existing gas and nuclear capacity in Arkansas and Iowa.

Prior to joining Synapse, I worked at EFI and XENERGY (now KEMA Consulting) and Zilkha Renewable Energy (now Horizon Wind Energy). At XENERGY and Zilkha I focused on policy and economic aspects of renewable energy. While at Zilkha, I authored a strategy and information plan for the development of wind farms in the western United States.

I hold a BS in Economics and Environmental Studies from Tufts University. A copy of my current resume is attached as Exhibit JI-1-B.

Q. Ms. Sommer, have you previously submitted testimony before this Commission?

A. No.

Q. What is the purpose of your testimony?

A. Synapse was asked by Joint Intervenors to investigate the following four issues regarding the proposed Big Stone II coal-fired generating facility:

A. The need and timing for new supply options in the utilities' service territories.

B. Whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

C. Whether the applicants have included appropriate emissions control technologies in the design of the proposed facility.

D. Whether the applicants have appropriately reflected the potential for the regulation of greenhouse gases in the design of the proposed facility and in their analyses of the alternatives.

This testimony and the testimony of our colleague Dr. Ezra Hausman presents the results of our investigations of Issue D. Our testimony regarding Issues A, B and C will be submitted on May 26, 2006.

Q. Please summarize your conclusions on the issue of whether the Big Stone II Co-owners have appropriately reflected the potential for the regulation of greenhouse gases in the design of the proposed facility and in their analyses of the alternatives.

A. Our conclusions on this issue are as follows:

1. Climate change is causing and can be expected in the future to cause "significant" environmental harm, as explained in detail in the Testimony of Dr. Ezra Hausman.

2. There is scientific consensus that emissions of carbon dioxide cause climate change.

3. Big Stone Unit II would emit significant amounts of additional carbon dioxide.

4. As a result, the Big Stone Unit II will pose a serious threat to the environment.

5. The potential for the regulation of carbon dioxide must be considered as part of any prudent cost estimates of Big Stone Unit II and alternatives.

6. However, the Big Stone II Co-owners have not adequately analyzed the potential for future carbon regulation.

7. The externality values for carbon dioxide established by the Minnesota Public Utilities Commission and used in resource planning by some of the Co-owners are meant to recognize "external" costs, or, in other words, costs that are not directly paid by utilities or their customers. The Minnesota Commission's externality values are not reflective of any concerns about the real costs of complying with future carbon dioxide regulation.

8. Synapse Energy Economics has developed a greenhouse gas allowance price forecast that reflects a range of prices that could reasonably be expected through 2030.

9. Adopting Synapse's range of prices would increase Big Stone Unit II's annual projected costs by $35,152,128 to $137,463,322 on a levelized basis.

Q. In the process of your investigation did you keep in mind the interests of the Big Stone Co-owners' customers?

A. Absolutely. Synapse regularly works for consumer advocates and has worked for over half of the members of the National Association of State Utility Consumer Advocates. Fundamentally, we believe that greenhouse gas regulation not only is an environmental issue. It also is a consumer issue in that it will have direct and tangible impacts on future rates.

Q. You have mentioned the terms "carbon dioxide regulation" and "greenhouse gas regulation." What is the difference between these two?

A. As we use these terms throughout our testimony, there is no difference. While we believe that the future regulation we discuss here will govern emissions of all types of greenhouse gases, not just carbon dioxide ("CO_2"), for the purposes of our discussion we are chiefly concerned with emissions of carbon dioxide. Therefore, we use the terms "carbon dioxide regulation" and "greenhouse gas regulation" interchangeably. Similarly, the terms "carbon dioxide price," "greenhouse gas price" and "carbon price" are interchangeable.

Q. Is it prudent to expect that a policy to address climate change will be implemented in the U.S. in a way that should be of concern to coal-dependent utilities in the Midwest?

A. Yes. The prospect of global warming and the resultant widespread climate changes has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change ("UNFCCC"), a treaty that the U.S. ratified in 1992, along with almost every other country in the world. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not signed the Kyoto Protocol. Nevertheless, individual states, regional groups of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, climate change as outlined in Dr. Hausman's testimony, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of regulating large point sources.

There are, of course, important uncertainties with regard to the timing, the emission limits, and many other details of what a carbon policy in the United States will look like.

Q. If there are uncertainties with regard to such important details as timing, emission limits and other details, why should a utility engage in the exercise of forecasting greenhouse gas prices?

A. First of all, utilities are implicitly assuming a value for carbon allowance prices whether they go to the effort of collecting all the relevant information and create a price forecast or whether they simply ignore future carbon regulation. In other words, a utility that ignores future carbon regulations is implicitly assuming that the allowance value will be zero. The question is whether it's appropriate to assume zero or some other number. There is uncertainty in any type of utility forecasting and to write off the need to forecast carbon allowance prices because of the uncertainties is not prudent.

For example, there are myriad uncertainties that utility planners have learned to address in planning. These include randomly occurring generating unit outages, load forecast error and demand fluctuations, and fuel price volatility and uncertainty. These various uncertainties can be addressed through techniques such as sensitivity and scenario analyses.

To illustrate that there is significant uncertainty in other types of forecasts, we think it is informative to examine historical gas price forecasts by the Energy Information Administration (EIA). Exhibit JI-1-C compares EIA forecasts from the period 1990 - 2006 with actual price data through 2005. The data, over more than a decade, shows considerable volatility, even on an annual time scale.[1] But the truly striking thing that jumps out of the figure is how wrong the forecasts have sometimes been. For example, the 1996 forecast predicted gas prices would start at $2.61/MMBtu and remain under $3/MMBTU through 2010, but by the year 2000 actual prices had already jumped to $4.82/MMBTu and by 2005 they were up to $8.09/MMBtu.

In view of the forecasting track record for gas prices one might be tempted to give up, and either throw darts or abandon planning altogether. But thankfully modelers, forecasters, and planners have taken on the challenge – and have improved the models over time, thereby producing more reliable (although still quite uncertain) price forecasts, and system planners have refined and applied techniques for addressing fuel price uncertainty in a rational and proactive way.

It is, therefore, troubling and wrong to claim that forecasting carbon allowance prices should not be undertaken as a part of utility resource decision-making because it is "speculative."

Q. Do the Co-owners have any opinions or thoughts as to when carbon regulation will happen?

A. No. Interrogatory 18 of Joint Intervenors' First Set and First Amended Set of Interrogatories[2] asked each of the Co-owners to state whether it:

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1 Gas prices also show terrific volatility on shorter time scales (e.g., monthly or weekly prices).

2 The Co-owners' response to Interrogatory 18 is attached as Exhibit JI-1-D.

> believes it is likely that greenhouse gas regulation (ghg) will be implemented in the U.S. (a) in the next five years, (b) in the next ten years, and (c) in the next twenty years.

None of the co-owners had any thoughts as to when or even if greenhouse gas regulation would occur. Two of the Co-owners (GRE and HCPD) claim to closely follow discussion of GHG regulation at the federal and State levels, but apparently had no opinions about what might result from such discussions.

Q. If the siting permit for Big Stone Unit II were to be approved and the unit were built, is carbon regulation an issue that could be reasonably dealt with in the future, once the timing and stringency of the regulation is known?

A. Unfortunately, no. Unlike for other power plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercial or economical method for post-combustion removal of carbon dioxide from supercritical pulverized coal plants. The Big Stone II Co-owners agree on that point. During the public hearing in Milbank held on September 13, 20005, the Co-owners presented several slides on the expected combined emissions from Big Stone Units I & II. The descriptive slide for the CO_2 emissions chart submitted to the South Dakota PUC states there is "no commercially available capture and sequestration technology." This slide is attached as Exhibit JI-1-E. Regardless of the uncertainty, this is an issue that needs to be dealt with before new resource decisions are made.

Q. Do other utilities have opinions about whether and when greenhouse gas regulation will come?

A. Yes. For example, James Rogers, CEO of Duke Energy, has publicly said "[I]n private, 80-85% of my peers think carbon regulation is coming within ten years, but most sure don't want it now."[3] Not wanting carbon regulation from a utility perspective is understandable because carbon price forecasting is not simple and easy, it makes resource planning more difficult and is likely to change "business

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[3] "The Greening of General Electric: A Lean, Clean Electric Machine," *The Economist,* December 10, 2005, at page 79.

as usual." For many utilities, including the Big Stone II Co-owners, that means that it is much more difficult to justify building a pulverized coal plant. Regardless, it is imprudent to ignore the risk.

Duke is not alone in believing that carbon regulation is inevitable and, indeed, some utilities are advocating for mandatory greenhouse gas reductions. In a May 6, 2005, statement to the Climate Leaders Partners (a voluntary EPA-industry partnership), John Rowe, Chair and CEO of Exelon stated, "At Exelon, we accept that the science of global warming is overwhelming. We accept that limitations on greenhouse gases emissions [sic] will prove necessary. Until those limitations are adopted, we believe that business should take voluntary action to begin the transition to a lower carbon future."

In fact, several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs into their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the U.S. electric sector's contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[4]

[4] Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

Even those in the electric industry who oppose mandatory limits on greenhouse gas regulation believe that regulation is inevitable. David Ratcliffe, CEO of Southern Company, a predominantly coal-fired utility that opposes mandatory limits, said at a March 29, 2006, press briefing that "There certainly is enough public pressure and enough Congressional discussion that it is likely we will see some form of regulation, some sort of legislation around carbon."[5]

Q. Do companies outside of electric utilities support greenhouse gas regulation?

Support for the passage of greenhouse gas regulation has been expressed by senior executives in companies such as Wal-Mart, General Electric, BP, Shell, and Goldman Sachs. For example, on April 4, 2006, during a Senate hearing on the design of a CO_2 cap-and-trade system, a representative of GE Energy said the following:

"GE supports development of market-based programs to slow, eventually stop, and ultimately reverse the growth of greenhouse gases (GHG)."

--David Slump, GE Energy, General Manager, Global Marketing, executive summary of comments to Senate Energy and Natural Resources Committee

Q. Why would so many electric utilities, in particular, be concerned about future carbon regulation?

A. Electricity generation is very carbon-intensive. Electric utilities are likely to be one of the first, if not the first, industries subject to carbon regulation because of the relative ease in regulating stationary sources as opposed to mobile sources (automobiles) and because electricity generation represents a significant portion of total U.S. greenhouse gas emissions. A new generating facility may have a book life of twenty to forty years, but in practice, the utility may expect that that asset will have an operating life of 50 years or more. By adding new plants, especially new coal plants, a utility is essentially locking-in a large quantity of

[5] Quoted in "U.S. Utilities Urge Congress to Establish CO2 Limits," Bloomberg.com, http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us

carbon dioxide emissions for decades to come. In general, electric utilities are increasingly aware that the fact that we do not currently have federal greenhouse gas regulation is irrelevant to the issue of whether we will in the future, and that new plant investment decisions are extremely sensitive to the expected cost of greenhouse gas regulation throughout the life of the facility.

Q. Have mandatory greenhouse gas emissions reductions programs begun to be examined and debated in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, legislative initiatives for a mandatory market-based greenhouse gas cap and trade program are under consideration.[6]

Several mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. Federal proposals that would require greenhouse gas emission reductions are summarized in Table 5.1 in Exhibit JI-1-F.

It is significant that the U.S. Congress is examining and debating these emissions reduction proposals. However, as shown in Figure 5.2 in Exhibit JI-1-F, the emissions trajectories contained in the proposed federal legislation are in fact quite modest compared with the emissions reductions that are anticipated to be necessary to achieve stabilization of atmospheric concentrations of greenhouse gases. Figure 5.2 in Exhibit JI-1-F compares various emission reduction trajectories and goals in relation to a 1990 baseline. U.S. federal proposals, and

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[6] Exhibit JI-1-F, at pages 11- 16.

even Kyoto Protocol reduction targets, are small compared with the current E.U. emissions reduction target for 2020, and the emissions reductions that most scientists claim will ultimately be necessary to avoid the most dangerous impacts of global warming.

Q. Are any states developing and implementing climate change policies that will have a bearing on resource choices in the electric sector?

A. Yes. A growing number of states are developing and implementing the following types of policies that will affect greenhouse gas emissions in the electric sector: (1) direct policies that require specific emissions reductions from electric generation sources; (2) indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (3) legal proceedings; or (4) voluntary programs including educational efforts and energy planning.[7]

Direct policies include the New Hampshire and Massachusetts laws imposing caps on carbon dioxide emissions from power plants in those states.

Indirect policies include the requirements by various states to either consider future carbon dioxide regulation or use specific "adders" for carbon dioxide in resource planning. It also includes policies and incentives to increase energy efficiency and renewable energy use, such as renewable portfolio standards. Some of these requirements are at the direction of state public utilities commissions, others are statutory requirements.

Lawsuits make up the majority of the third category. For example, several states are suing the U.S. Environmental Protection Agency (EPA) to have carbon dioxide regulated as a pollutant under the Clean Air Act.

Among the voluntary programs undertaken at the state level are the climate change action plans developed by 28 states.

[7] Exhibit JL-1-F, at pages 16 through 20.

But states are not just acting individually; there are a number of examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g., Southwest governors and Midwestern legislators) to development of a regional cap and trade program through the Regional Greenhouse Gas Initiative in the Northeast ("RGGI"). The objective of the RGGI is the stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019. These regional activities are summarized in Table 5.5 in Exhibit JI-1-F.

Q. Have any states adopted direct policies that require specific emissions reductions from electric sources?

A. Yes. The states of Massachusetts, New Hampshire, Oregon and California have adopted policies requiring greenhouse gas emission reductions from power plants.[8]

Q. Do any states require that utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement?

A. Yes. As shown in Table 1 below, several states require companies under their jurisdiction to account for the emission of greenhouse gases in resource planning.

[8] Exhibit JI-1-F, Table 5.3 on page 18.

Table 1. Requirements for Consideration of Greenhouse Gas Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12) (2005)

Q. What carbon dioxide values are being used by utilities in electric resource planning?

A. Table 2 below presents the carbon dioxide costs, in \$/ton CO_2, that are presently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table 2. Carbon Dioxide Costs Used by Utilities

Company	CO2 emissions trading assumptions for various years (\$2005)
PG&E*	\$0-9/ton (start year 2006)
Avista 2003*	\$3/ton (start year 2004)
Avista 2005	\$7 and \$25/ton (2010) \$15 and \$62/ton (2026 and 2023)
Portland General Electric*	\$0-55/ton (start year 2003)
Xcel-PSCCo	\$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	\$0-61/ton (start year 2008)
Pacificorp 2004	\$0-55/ton
Northwest Energy 2005	\$15 and \$41/ton
Northwest Power and Conservation Council	\$0-15/ton between 2008 and 2016 \$0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to \$2005 using GDP implicit price deflator.

Q. How should utilities plan for and mitigate the risk of greenhouse gas regulation?

A. The key part of that question is "plan for the risk of greenhouse gas regulation." Mitigating risk begins with the resource planning process and the decision as to the demand-side and supply-side options that should be pursued. A utility that chooses to go forward with a new, carbon intensive energy resource without proper consideration of carbon regulation is imprudent. To give an analogy it would be like choosing to build a gas-fired power plant without consideration of the cost of gas because one believes that building the plant is "worth it" regardless of what gas might cost.

A utility that desires to be prudent about the risk of carbon regulation would, at a minimum, consider carbon regulation by developing an expected carbon price forecast as well as reasonable sensitivities around that case.

Q. Please explain how Synapse developed its carbon price forecast.

A. Our forecast is described in more detail in Exhibit JI-1-F starting on page 39.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices will reflect the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). We expect that the widest uncertainty in our forecasts will begin at the end of this decade, that is, from $10 to $40 per ton of CO_2 in 2020, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward a marginal mitigation cost. This number will depend on currently uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that, by this time, the least expensive mitigation options (such as simple energy efficiency and fuel switching) will have been exhausted. Our projection for greenhouse gas emissions costs at the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

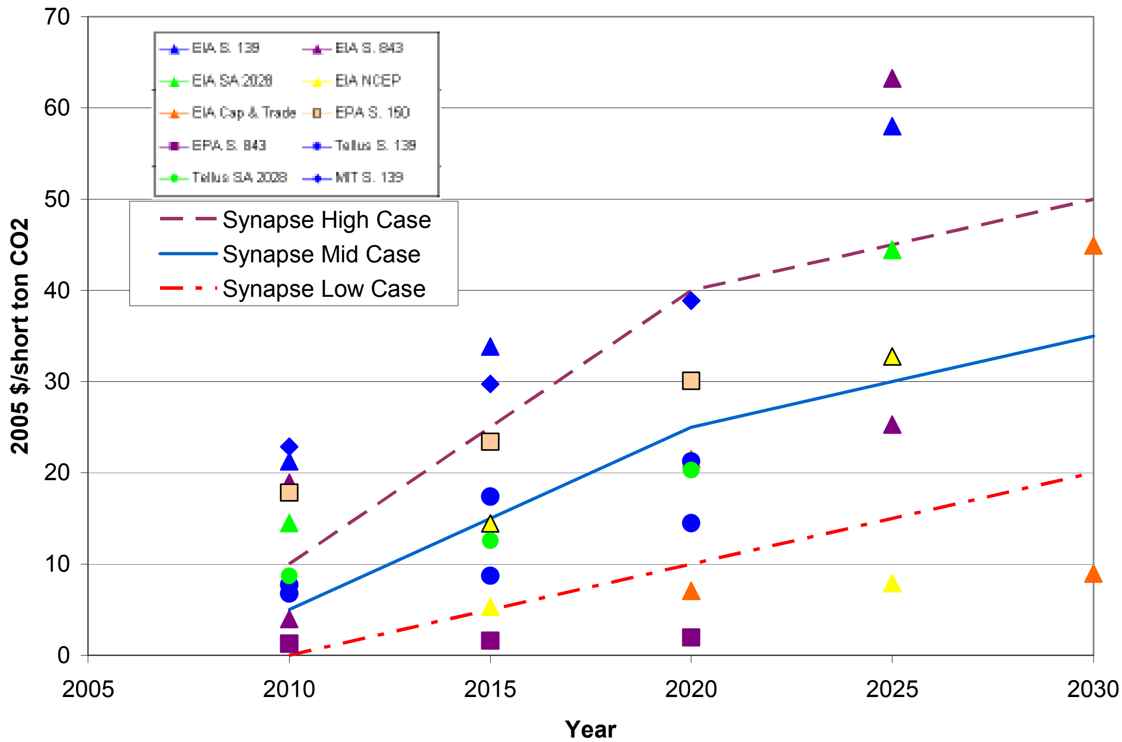
We currently believe that the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, making the most likely scenario closer to (though not equal to) low case scenarios than the high case scenario. We expect that the probability of taking this path will increase over time, as society learns more about optimal carbon reduction policies.

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices will increase due to the interplay of factors such as the level of carbon constraints required and technological innovation. As discussed in Exhibit JI-1-F, scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that will keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though we have not quantified the cost of such deeper cuts on a per ton basis.

Q. What is Synapse's forecast of carbon dioxide emissions prices?

A. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 1 below. This figure superimposes Synapse's forecast on the results of other cost analyses of proposed federal policies:

Figure 1. Synapse Carbon Dioxide Prices



Q. What is Synapse's levelized carbon price forecast?

A. Synapse's forecast, levelized[9] over 20 years, 2011 – 2030, is provided in Table 3 below.

Table 3. Synapse's Levelized Carbon Price Forecast (2005$/ton)

Low Case	Mid Case	High Case
$7.8	$19.1	$30.5

[9] A value that is "levelized" is the present value of the total cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Q. The Minnesota Public Utilities Commission has established environmental externality values for a number of pollutants including CO_2. Wouldn't it be sufficient and more efficient to simply use the CO_2 externality values? The effect is the same, to bias resource selection towards non-CO_2 emitting resources.

A. That would appear to be an easy solution, but the MN PUC values are meant to reflect external costs arising from damage to the environment caused by climate change (as a percentage of GDP). The Commission's order of January 3, 1997 explained: [10]

> The environmental values for CO_2 quantified in this Order follow MPCA witness Ciborowski's general methodology. First, Ciborowski estimated **long-term global costs** based on the existing economic literature and **discounted** them to current values. Then, he divided that amount by the amount of long-term CO_2 emissions to arrive at an average cost per ton. Ciborowski essentially converted published damage estimates made by economists from percentages of gross domestic product (GDP) into costs per ton of CO_2.

The full order is attached as Exhibit JI-1-G. Clearly this order shows that the Minnesota environmental externality values contain no consideration of future carbon regulation and the *actual* costs that regulation would impose on utilities. Indeed, the range of CO_2 values adopted by the Minnesota PUC is much smaller than the range of Synapse's price forecasts, \$0.35 – 3.64 per ton of CO_2 (2004\$).

Q. Have the Big Stone II co-owners adequately considered the risk of greenhouse gas regulation?

A. No. The Co-owners' approach is what might be called keeping their heads in the sand and hoping that the problem of global warming goes away. For example, the Co-owners could not answer basic questions about the United Nations Framework Convention on Climate Change. Request for Admission No. 22 in the Joint Intervenors' First Set of Requests for Admission asked the Co-owners to:

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[10] Page 27 of the Order Establishing Environmental Cost Values in Docket No. E-99/CI-93-583 issued January 3, 1997.

> Admit that in 1992 the United Nations Framework Convention on Climate Change was adopted [IPCC 2005, p 5].

The Co-owners responded by saying that:

> Applicant has made reasonable inquiry and the information known to it is insufficient to enable Applicant to admit or deny this statement.

Similarly, Request for Admission No. 25 asked the Co-owners to:

> Admit that the most recent Assessment Report released by the IPCC is the Third Assessment Report (TAR), released in 2001, and that part of the TAR is the report of the Working Group I of the IPCC, entitled "Climate Change 2001: The Scientific Basis."

Again, the Co-owners responded, in part:

> Applicant has made reasonable inquiry and the information known to it is insufficient to enable Applicant to admit or deny this statement.

In *twenty* separate instances, the Co-owners could not answer requests for admission requiring them to do nothing more than admit facts that could easily be verified by an internet search (starting with the internet addresses that Joint Intervenors in many cases provided in the questions) or by referring to the document(s) attached to the request. Attached as Exhibit JI-1-H, is the Joint Intervenors' First Set of Requests for Admission with these twenty responses highlighted.

Q. How are such responses relevant to the issue of considering carbon regulation in resource planning?

A. If a utility does not rely upon outside expertise to, at a basic level, advise the utility on future carbon regulation and second to forecast carbon allowance prices, it must rely upon its own knowledge and information gathering to do so. A major step in that process is to understand the various parties involved and what their recommendations mean to policymakers. Organizations such as the Intergovernmental Panel on Climate Change are well recognized and regarded and their thoughts on topics such as climate change do not go by the wayside. The inability to answer these basic questions, let alone put in the small effort that would be necessary to answer such questions, bodes poorly for the Co-owners' decision-making.

Q. Did the Co-owners reflect any potential greenhouse gas regulations in their resource planning for Big Stone II?

A. No. In certain instances they used the Minnesota PUC environmental externality value for carbon dioxide, which as we discussed above is not adequate consideration of regulatory risk and uncertainty.

Q. Are the Big Stone II Co-owners already heavily dependent upon coal-fired generation?

A. Yes. The testimony in this proceeding reveals that each of the Co-owners already is heavily dependent upon coal-fired generation. Although some Co-owners are making some efforts to add wind, participation in Big Stone II will further increase the Co-owners' dependence upon coal-fired generation and, consequently, their exposure to future greenhouse gas regulations.

For example, Otter Tail Power's testimony in this proceeding reveals that as of 2004, 60.3 percent (winter) to 65.3 percent (summer) of the Company's generating capacity was coal-fired.[11] When oil and natural gas fired capacity is included, more than 75 percent of Otter Tail's current generating capacity is fossil-fired.

GRE's 2006 generation mix is 76 percent from coal, not including additional coal-fired generation that might be the sources for the other purchased power listed in the Company's testimony.[12]

CMMPA's listing of its existing and planned capacity resources includes 43 MW of coal-fired capacity (75 percent of the total) and 13.5 MW of wind.[13]

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[11] Applicants' Exhibits 10-D and 10-E.

[12] Applicants' Exhibit 2, page 14, lines 19-23.

[13] Applicants' Exhibit 6, page 10, lines 1-2.

Seventy-six percent of Montana-Dakota Utilities existing owned-generation is coal-fired.[14] However, despite this reliance on coal, Montana-Dakota Utilities 2005 Integrated Resource Plan reveals that, other than possible purchases from other utilities or the energy market, the only new baseload options that the company was considering were coal-fired units.[15]

Approximately 50 percent of MRES' existing capacity, and all of its baseload capacity, is coal-fired.[16]

Approximately 59 percent of SMMPA's existing generating capacity is coal-fired.[17]

Finally, Heartland's existing resources appear to be a mix of coal-fired generation and purchased power contracts.[18] Heartland has indicated that from 2013 to 2020, i.e., after the end of its purchased power agreement with Nebraska Public Power District, it plans to have the following resources available for its customers: Laramie River Station (50 MW); Customer-owned peaking generation (24 MW); Big Stone Unit II (25 MW); and Whelan Energy Center Unit 2 (80 MW).[19] This means that all of the resources that Heartland plans to have available for its customers during these years will be fossil-fired, and approximately 86 percent will be coal-fired.

Q. How much additional CO_2 will Big Stone II emit into the atmosphere?

A. At its projected 88 percent capacity factor (i.e., 4625 GWH), Big Stone II will emit approximately 4,506,000 tons of CO_2 annually.

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14 Applicants' Exhibit 11, page 8, lines 9-17.

15 *Montana-Dakota Utilities Co. 2005 Integrated Resource Plan submitted to the Montana Public Service Commission*, dated September 15, 2005, at pages (iii) and (iv).

16 Applicants' Exhibit 14, at page 9, line 6, to page 10, line 3.

17 Applicants' Exhibit 13, page 4, line 14, to page 5, line 8.

18 Applicants' Exhibit 15, page 16, lines 16-23.

19 Co-owners' Response to Interrogatory 62 of the Intervenors' Sixth Set of Interrogatories in this Docket.

Q. Would incorporating Synapse's carbon price forecast have a material effect on the economics of building and operating the proposed Big Stone II Project?

A. Yes. For illustrative purposes, we have calculated the CO_2 cost of a new fossil-fuel fired generating unit built in 2011 using each case of our carbon price forecast levelized over the 20-year period from 2011 to 2030.

Table 4. CO_2 Cost of New Fossil-Fuel Resources

For a new plant online in 2011

	Supercritical PC	Combined Cycle	IGCC	Source Notes
Size (MW)	600	600	535	1
CO_2 (lb/MMBtu)	208	110	200	1
Heat Rate (Btu/KWh)	9,369	7,400	9,612	1
CO_2 Low Price (2005$/ton)	7.80	7.80	7.80	2
CO_2 Mid Price (2005$/ton)	19.10	19.10	19.10	2
CO_2 High Price (2005$/ton)	30.50	30.50	30.50	2
CO_2 Low Cost per MWh	$7.60	$3.17	$7.50	
CO_2 Mid Cost per MWh	$18.61	$7.77	$18.36	
CO_2 High Cost per MWh	$29.72	$12.41	$29.32	

1 - From Applicants' Exhibit 23-A
2 - Synapse's carbon allowance price forecast levelized over 20 years at 7.32% real discount rate

As demonstrated in Table 4, the cost per MWh attributable to a supercritical coal plant like Big Stone II from greenhouse gas regulation is quite significant. From a purely qualitative standpoint, it is very difficult to imagine that other resources would not be more cost-effective than Big Stone II with the addition of *$18.61/MWh* in operating costs from our mid-case CO_2 price forecast.

According to Applicants' Exhibit 23-A, Burns & McDonnell's *Analysis of Baseload Generation Alternatives*, the busbar cost of Big Stone II is $50.71/MWh (2005$) for investor-owned utilities (IOUs) and $40.85/MWh (2005$) for public power. An $18.61/MWh increase in operating costs would represent a 37% increase in cost per MWh of Big Stone II generation to the Big Stone II investor owned utilities and a 46% increase to the public power Co-owners.

Q. What would be the annual CO_2 cost to the Big Stone II Co-owners?

A. Assuming the *Analysis of Baseload Generation Alternatives* will accurately reflect the operating parameters of Big Stone Unit II including an 88% capacity factor, the range of annual, levelized cost to the Big Stone II Co-owners of CO_2 regulation would be:

Low Case - 4,625,280 MWh · $7.74/MWh = $35,152,128

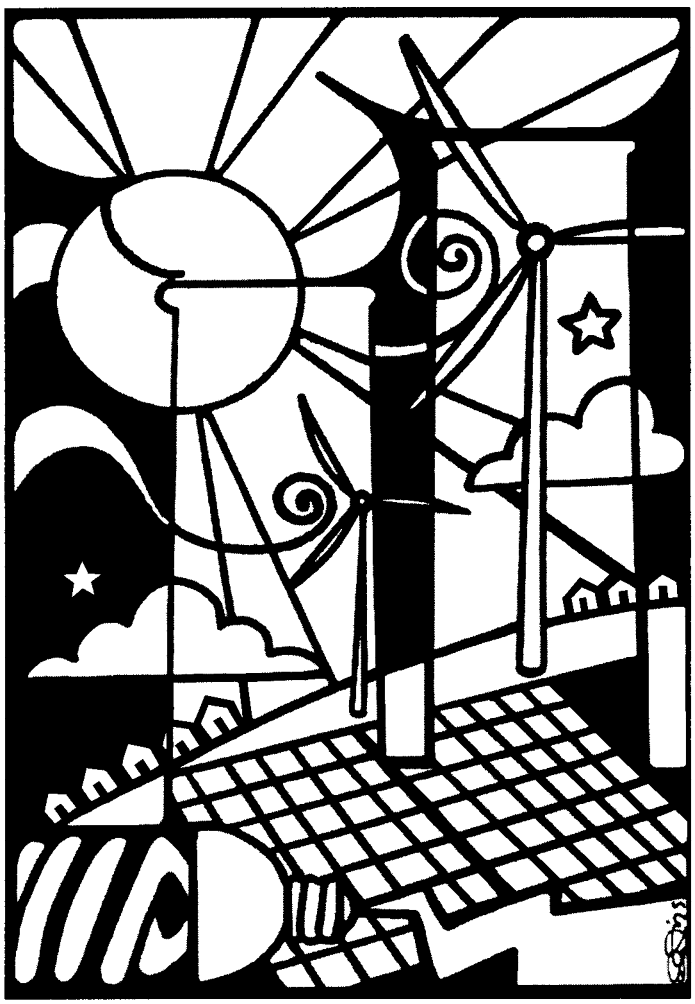
Mid Case - 4,625,280 MWh · $19.60/MWh = $86,076,461

High Case - 4,625,280 MWh · $30.39/MWh = $137,463,322

Q. Does this conclude your testimony?

A. No. The remainder of our testimony will be filed on May 26, 2006.

A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative



By Susan M. Zinga and Andy McDonald

A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative

February 2008

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INTRODUCTION

Kentucky is at an energy crossroads. As nations and many U.S. states are taking swift action toward renewable energy and energy efficiency, Kentucky remains reliant on burning coal for our electricity needs. There are several problems with this approach. First, the cost of coal is increasing, a trend that is likely to continue due to the higher price of coal itself, the need for advanced pollution control on power plants, impending greenhouse gas regulation, dramatically increasing construction costs for coal-fired power plants, and other factors. These increased costs will be felt by utilities, cooperatives, and customers alike. Second, coal is harming the health of Kentuckians and taking a toll on the quality of the environment on which we depend. This report notes just a few of these many health threats as they have been extensively documented elsewhere.

We cannot deny the harmful, costly impacts of coal. Fortunately we have the option to diversify our electricity sources by using clean, renewable energy, and by deploying energy efficiency programs to lower our electricity needs while still receiving the same services. Kentucky's electric cooperatives can take leadership in this area, fulfilling their mission to serve the best interests of their communities. East Kentucky Power Cooperative (EKPC) is particularly well-suited for this task. East Kentucky Power Company (EKPC) is a not-for-profit generation and transmission company providing wholesale electricity to 16 distribution companies serving 89 counties in Kentucky. It generates over 97% of its electricity from coal-fired power plants.[1] EKPC currently intends to construct a new coal-fired power plant in Clark County, Kentucky, near the Madison County line. Such power plants will contribute additional greenhouse gases, particulate matter (soot), mercury, and other hazardous compounds into the air, endangering our health and the environment upon which we depend.

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[1] Coalition for Responsible Economies, Natural Resources Defense Council, and Public Service Enterprise Group, Benchmarking *Air Emissions of the 100 Largest Electric Power Producers in the United States, 2004*, April 2006, p. 20.

This paper details how East Kentucky Power Cooperative can meet its projected demand for electricity through a portfolio of energy efficiency programs and renewable energy resources while helping its customers realize savings on their monthly electric bills.[2] This portfolio of options:

- Offers low-income residents, among others, the opportunity to lower their monthly bills.
- Helps businesses be more competitive by reducing their energy bills.
- Facilitates the penetration of high-efficiency appliances and equipment in homes and businesses.
- Induces lower prices for high-efficiency equipment by encouraging greater demand for these products, which in turn necessitates a greater supply at a lower average cost.
- Educates energy users and makes them more knowledgeable about their future product purchases and wiser about their daily energy consumption.
- Avoids the additional financial risk inherent in constructing and operating fossil-fuel power plants at a time when new federal legislation seems very likely to make the use of coal much more expensive.
- Helps protect Kentucky's air quality and the health of Kentucky's people and ecosystems, thus allowing them to be more productive.

Through the implementation of this portfolio over ten years, EKPC could potentially obviate its need for coal-fired generation with energy efficiency measures that will save 743,544 megawatt-hours (MWh) per year, while offering 455 megawatts (MW) of demand reduction, and providing electricity from renewable energy resources totaling 1,076,761 MWh annually and with 210 MW of capacity. By supplanting discrete fossil-fuel generating units with smaller, scalable energy efficiency projects and renewable energy generation, EKPC customers can respond to increases in

[2] An approach to meeting EKPC's needs through renewable energy and energy efficiency would also provide a significant boost to the local economy. However, quantification of this economic benefit is beyond the scope of this paper.

customer energy consumption over time instead of paying for generating capacity that remains unused in the short-term.

It is important to note that cooperatives like EKPC don't have to take on this task alone. Numerous environmental, public health, economic development, and service organizations are willing to assist in executing energy efficiency and renewable energy programs; in fact this paper serves as an example of such groups' willingness to shape strategies that help meet our energy needs.

OVERVIEW OF EAST KENTUCKY POWER COOPERATIVE

EKPC's member cooperatives, also known as distribution co-ops, are heavily weighted with energy sales to residential customers. In fact, this customer class serves nearly 470,000 residential customers, representing more than half of EKPC's annual energy sales. EKPC member co-ops also serve more than 28,000 commercial customers and 1,400 industrial customers with energy sales that are 11% and 32% respectively of total sales (see Tables 1 and 2).[3]

EKPC's Dominant Customer Class—Residential

According to estimates by the U.S. Department of Energy, average residential electricity consumption by Kentucky households is 12,893 kWh per year, which is the highest across nine Midwest states.[4] This is due in part to the fact that Kentucky has the highest penetration rate of electric water and space heating of any of these Midwest states. Twenty-eight percent of all households in Kentucky use electricity for space heating, which includes an 8% penetration rate for heat pumps.[5] Additionally, 89% of all clothes dryers and 83% of stoves in Kentucky are electric, and at 61%, more than half of all water heating is electric.[6] For EKPC however, the penetration rate for electric water heating is even higher at 87%.[7]

Annual revenue and sales data submitted to the Kentucky Public Service Commission by EKPC's distribution co-ops shows that rural electric cooperative customers clearly hover close to the statewide average for household electricity usage. The lowest average monthly usage for residential customers is 1,043 kWh in Grayson RECC, and the highest is 1,264 kWh for customers in the Salt River Electric

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[3] 2006 Annual Report Statistics from the Commonwealth of Kentucky Public Service Commission.

[4] Kentucky is one of nine states comprising the Midwest Energy Efficiency Alliance. The other states are Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio, and Wisconsin. Average annual usage by state is listed on Table 4-7 in a report of the Midwest Energy Efficiency Alliance entitled *Midwest Residential Market Assessment and DSM Potential Study* (March 2006), based on data gathered from the U.S. Energy Information Administration, *Electric Sales and Revenue 2003 Spreadsheets*.

[5] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, March 2006, p. 38.

[6] Ibid., Table 4-16, p. 43.

[7] Penetration rate as reported in EKPC 2006 Integrated Resource Plan.

Cooperative. Of course, these averages vary due to a number of factors, including differences in income levels and home size, which can affect the quantity and size of appliances as well as the type and size of heating and cooling equipment. Nevertheless, valid comparisons can be made between the average electricity price paid by customers in each of EKPC's distribution cooperatives. Grayson RECC's residential customers pay the highest average price per kWh, at $0.0910, of all 16 EKPC distribution co-ops, while Nolin RECC's residential customers enjoy the lowest at $0.0774 per kWh (see Table 3).[8]

EKPC's Low-Income Customers

According to the U.S. Census Bureau, there are over 500,000 people living in poverty in the 89 counties served by EKPC. At 35%, Owsley County has the highest percentage of low-income residents in the EKPC service territory, and is one of the poorest counties in the nation given its proportion of households below the federal poverty rate.[9] Table A-1 in the Appendix shows the percentage of individuals of all ages living in poverty for all counties served by an EKPC distribution cooperative. It seems clear that low-income households constitute a significant portion of EKPC's residential customer class.

Income constraints often make it difficult for poverty-level households to pay their electric bills. These same financial constraints mean low-income customers typically face challenges allocating their monetary resources or lack the cash flow to invest in energy efficiency or renewable energy programs, even if these programs can reduce their monthly bills and save them money over time. Understandably, EKPC member co-ops may have reservations about developing and promoting energy efficiency programs targeting customers unable to make the necessary investments. But this hurdle can be overcome in two ways. First, programs can be designed to eliminate the barrier of high up-front energy efficiency and/or renewable energy investments. Such programs are successfully underway at other rural electric cooperatives. Effective marketing can help clarify the benefits of these programs and correct any misinformation or false perceptions about economic

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[8] The average residential price of electricity is provided by annual data from the Kentucky Public Service Commission website for Rural Electric Cooperatives. Annual Report Statistics for 2006 present revenues and kWh sales by customer class, which is used to determine cost per kWh. It is reasonable to assume that revenue data includes flat monthly customer charges as well as variable monthly environmental and fuel surcharges.

[9] U.S. Census Bureau, *Small Area Income & Poverty Estimates for Kentucky Counties, 2004.*

barriers. Second, program measures can be delivered in ways that leverage the resources of the social welfare infrastructure and volunteer community. These approaches are discussed later in more detail as part of the recommended portfolio.

Table 1

Member Distribution Cooperatives of East Kentucky Power Cooperative with Number of Customers by Class

Rural Electric Cooperative	Residential	Commercial	Industrial	Other	Total	Residential % of Total	Non-Residential % of Total
Big Sandy RECC	11,985	953	151	0	13,089	92%	8%
Blue Grass Energy Cooperative Corp.	51,000	2,090	17	46	53,153	96%	4%
Clark Energy Cooperative	23,868	1,608	3	29	25,508	94%	6%
Cumberland Valley Electric, Inc.	21,861	1,325	117	0	23,303	94%	6%
Farmers RECC	21,745	1,618	6	8	23,377	93%	7%
Fleming-Mason Energy Cooperative	21,530	1,561	5	268	23,364	92%	8%
Grayson RECC	14,239	1,200	76	1	15,516	92%	8%
Inter-County Energy Cooperative Corporation	23,629	1,122	118	0	24,869	95%	5%
Jackson Energy Cooperative	46,652	3,289	185	758	50,884	92%	8%
Licking Valley RECC	15,961	1,119	5	0	17,085	93%	7%
Nolin RECC	28,643	1,974	2	30	30,649	93%	7%
Owen Electric Cooperative	52,935	1,930	27	249	55,141	96%	4%
Salt River Electric Cooperative	41,770	2,462	12	229	44,473	94%	6%
Shelby Energy Cooperative	14,485	536	8	24	15,053	96%	4%
South Kentucky RECC	57,044	3,689	414	722	61,869	92%	8%
Taylor County RECC	21,774	2,158	254	297	24,483	89%	11%
TOTAL CUSTOMERS	**469,121**	**28,634**	**1,400**	**2,661**	**501,816**	**93%**	**7%**

Table 2

2006 Energy Usage by Customer Class

Rural Electric Cooperative	Residential MWh Sales	Commercial MWh Sales	Industrial MWh Sales	Other MWh Sales	Total Energy Sales (MWh)	Res. % of Total	Comm. % of Total	Ind. % of Total
Big Sandy RECC	176,295	13,640	57,196	0	247,131	71%	6%	23%
Blue Grass Energy Cooperative Corp.	766,303	126,275	282,633	980	1,176,191	65%	11%	24%
Clark Energy Cooperative	317,021	86,096	16,391	649	420,158	75%	20%	4%
Cumberland Valley Electric, Inc.	309,629	22,238	161,824	0	493,691	63%	5%	33%
Farmers RECC	305,876	69,610	120,167	436	496,089	62%	14%	24%
Fleming-Mason Energy Cooperative	272,831	124,938	495,549	2,516	895,834	30%	14%	55%
Grayson RECC	178,207	16,829	54,965	83	250,083	71%	7%	22%
Inter-County Energy Cooperative Corporation	340,651	18,596	76,296	0	435,544	78%	4%	18%
Jackson Energy Cooperative	655,386	58,696	165,128	20,686	899,897	73%	7%	18%
Licking Valley RECC	218,403	46,232	14,675	0	279,309	78%	17%	5%
Nolin RECC	433,904	107,326	204,511	1,460	747,200	58%	14%	27%
Owen Electric Cooperative	679,964	207,408	1,177,002	12,267	2,076,642	33%	10%	57%
Salt River Electric Cooperative	633,657	170,088	140,023	2,440	946,208	67%	18%	15%
Shelby Energy Cooperative	217,782	68,136	156,441	126	442,486	49%	15%	35%
South Kentucky RECC	739,246	62,694	304,038	11,359	1,117,337	66%	6%	27%
Taylor County RECC	291,187	31,422	173,846	4,723	501,177	58%	6%	35%
TOTAL ENERGY SALES (MWh)	**6,536,341**	**1,230,225**	**3,600,687**	**57,726**	**11,424,978**	**57%**	**11%**	**32%**

Table 3

East Kentucky Power Cooperative
2006 Residential Rate Statistics by Distribution Co-op

EKPC Cooperative	Average kWh Usage	Average Monthly Residential Bill	Average Price per kWh
Big Sandy RECC	1,226	$98.68	$0.081
Blue Grass Energy Cooperative Corp.	1,252	$100.44	$0.080
Clark Energy Cooperative	1,107	$95.41	$0.086
Cumberland Valley Electric, Inc.	1,180	$95.10	$0.081
Farmers RECC	1,172	$90.99	$0.078
Fleming-Mason Energy Cooperative	1,056	$85.56	$0.081
Grayson RECC	1,043	$94.95	$0.091
Inter-County Energy Cooperative Corporation	1,201	$99.46	$0.083
Jackson Energy Cooperative	1,171	$104.40	$0.089
Licking Valley RECC	1,140	$95.93	$0.084
Nolin RECC	1,262	$97.73	$0.077
Owen Electric Cooperative	1,070	$92.59	$0.087
Salt River Electric Cooperative	1,264	$99.35	$0.079
Shelby Energy Cooperative	1,253	$102.32	$0.082
South Kentucky RECC	1,080	$86.66	$0.080
Taylor County RECC	1,114	$90.80	$0.082
Maximum Residential Electricity Price ($/kWh)			$0.091
Minimum Residential Electricity Price ($/kWh)			$0.077
Median Residential Electricity Price ($/kWh)			$0.081

FINANCIAL RISKS ASSOCIATED WITH COAL

At first glance, the cost of producing each megawatt-hour of electricity with coal may seem deceptively appealing. Yet upon further investigation, there are many reasons why coal-fired generation is actually the least attractive option for addressing future electricity needs. Price escalation for the construction of new coal-fired plants, which are already the most expensive fossil fuel option in terms of capital costs, coupled with "carbon risk," makes investments in new coal-fired power plants fiscally irresponsible. In addition, there are many outright and implicit costs borne by citizens and taxpayers which disguise the true price of this fuel.

Many of these costs are associated with coal pollution and the increasing regulatory measures that try to control this pollution. Sulfur dioxide and nitrogen oxides released from coal-fired power plants are currently regulated, although the stringency of these regulations will increase substantially in 2009 and again in 2015 under the Clean Air Interstate Rule. As air quality regulations become more stringent, the cost of using coal increases relative to other supply-side and demand-side options because coal-fired plants are the most polluting sources. This increase is a result of the cost of pollution control equipment (or pollution credits), and because the efficiency of a coal-fired plant diminishes as additional pollution control devices are added, lowering its output and further jeopardizing its status as a potentially low-cost alternative.

Further regulation, especially of greenhouse gases like carbon dioxide (CO_2) and nitrous oxide, seems inevitable. This will greatly raise the cost of coal-fired generation once again. One study estimates that the cost of CO_2 from a coal-fired power plant will be $18.45 per MWh.[10] Even the staff of the Kentucky Public Service Commission recommends that Integrated Resource Plans submitted by electric utilities estimate the impact of future CO_2 emission restrictions.[11]

In addition to increased generation costs caused by regulatory pressures, the cost of the fuel itself has been rising steadily with no signs of relenting. EKPC's cost

[10] Synapse Energy Economics, *Climate Change and Power: Carbon Dioxide Emission Costs and Electricity Resource Planning*, June 8, 2006, p. 3.

[11] Staff Report of the Kentucky Public Service Commission in the matter of the 2005 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, February 15, 2006, p. 24.

of coal has risen by 72% in 5 years.[12] This trend is likely to continue. According to the U.S. Department of Energy, ". . . the Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions."[13]

Although the costs of mining, transporting, and preparing coal for electricity production are already embedded in its market price, there are many additional costs borne by society, not the coal industry. These are known as externalities, and they include the costs of damage to our health, water resources, air quality, mountain and forest ecosystems, highways, bridges, and humans—both individuals and communities—who find themselves in the midst of coal extraction activity.

Coal-fired power plants emit a wide range of air pollutants whose harmful health effects are well-established. These power plants are the nation's major source of sulfur dioxide, and emit tons of arsenic, lead, and chromium compounds, as well as hydrogen fluoride and hydrochloric acid, each year.[14] Additionally, these facilities are the largest U.S. source of human-made mercury pollution, emitting approximately 48 tons per year. These chemicals are hazardous to human health, and they contaminate our environment.

Many studies demonstrate that poor air quality results in increased asthma attacks, lung cancer, heart attacks, emergency room visits, and even mortality. One study estimates that every year in Kentucky alone, emissions from power plants cause nearly 1,000 deaths, over 600 hospitalizations, and 19,000 asthma attacks.[15] These costs are paid not only by the families of those who are ill, but by society at large as insurance companies and the government cover their medical costs and their employers suffer from work absences.

In addition to the harmful effects on human health, coal-fired power plants have a huge impact on natural ecosystems. The chemical pollution produced by acid mine drainage from coal mining operations significantly impacts the purity of the region's water systems, necessitating mitigation costs of more than $40 million

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[12] East Kentucky Power Cooperative, *2006 Annual Report*, Five-Year Statistical Summary.

[13] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 2007*, p. 98.

[14] Natural Resources Defense Council, *Coal in a Changing Climate*, February 2007, p. 13.

[15] Clean Air Task Force, *Death, Disease and Dirty Power: Mortality and Health Damage Due to Air Pollution from Power Plants*, October 2000, p. 6.

annually in Kentucky, Tennessee, Virginia, and West Virginia alone.[16] Other costs borne by Kentucky taxpayers include recovering from catastrophes such as breaks in sludge impoundments created from the waste of washing coal. In 2000, Kentuckians were faced with a break in a sludge impoundment of more than 300 million gallons of slurry that destroyed homes and killed aquatic life in more than 20 miles of streams.[17]

[16] Natural Resources Defense Council, *Coal in a Changing Climate*, p. 8.

[17] Ibid., p. 9.

ENERGY EFFICIENCY POTENTIAL IN KENTUCKY

Unlike other Midwest states, Kentucky has high residential electric usage and relatively few state or utility-sponsored energy efficiency programs. Therefore, it's not surprising that the Midwest Energy Efficiency Alliance (MEEA) found that Kentucky's technical potential[18] for energy efficiency is greater than 30%, which is higher than any of the other Midwest states analyzed in their 2006 study.[19] More than half of the achievable energy efficiency can be captured at a cost of 10 cents or less per kWh conserved.[20] Approximately 85% of these savings can be achieved by focusing on three main areas: space heating and cooling, water heating, and lighting.

In addition, refrigeration represents 7% of Kentucky's achievable residential energy efficiency potential. Total residential electric consumption can be reduced 0.3%, by replacing inefficient refrigerators with EnergyStar refrigerators.[21] It seems reasonable to assume that these statewide characteristics are reflected in EKPC's service territory. In the case of EKPC, if all inefficient refrigerators were replaced, residential energy usage would decline by almost 20,000 MWh annually.

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[18] Technical potential is generally regarded as the quantification of energy savings that could be realized if energy efficiency measures were applied in all technically feasible applications regardless of cost. Achievable potential is a subset of technical potential. It refers to the energy savings that could be realistically achieved through program or policy interventions. Some of the achievable potential is considered naturally occurring, such as changes in the marketplace for energy efficiency measures. The second component of achievable potential is due to higher appliance and equipment standards. The remaining portion of achievable potential comes from energy efficiency gains resulting from programs and policies specifically designed to advance the penetration of energy efficient appliances and equipment in society.

[19] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, Table 5-15, p. 62.

[20] Ibid.

[21] Ibid., p. 7.

Energy Efficiency Programs for EKPC

The energy efficiency programs recommended as part of this portfolio are based on mature programs that have been adopted by numerous other utilities (see Table 4). Brief descriptions of each program can be found in Table A-2 in the Appendix. As should be the case with any robust energy efficiency portfolio, the one recommended here offers all customer classes at least one program to meet their needs. The following 11 programs are in no way meant to represent all of the achievable energy efficiency programs available to EKPC.

Although electric rates will rise minimally when energy efficiency is delivered by utilities and their partners, they will rise less than the incremental amount incurred when the cost of new baseload generation is added to rates. By participating in energy efficiency programs, EKPC customers will be able to partially or fully negate the impact of slightly higher kilowatt-hour rates through actual savings on their electric bills due to decreased energy usage. In addition, the energy-efficient equipment and appliances offered in these programs provide comparable or improved functionality to the consumer.

Table 4

Energy Efficiency Programs Recommended for East Kentucky Power Cooperative

Program Name	Cost of Saved Energy ($/kWh)	Measure Lifetime	Cumulative Lifetime Energy Savings (MWh)	Cumulative Program Annual Energy Savings in Year 10 (MWh)	Cumulative Annual Summer Demand Savings (MW)	Cumulative Annual Winter Demand Savings (MW)
Air Source Heat Pump Retrofit	0.017	20	3,486,000	174,300	9	244
Residential Lighting	0.018	4	240,000	60,000	8	8
Load Control Programmable Thermostat	0.018	10	1,926,000	192,600	140	0
Air Conditioner Exchange	0.058	12	54,000	4,500	7	0
Residential Water Heater Replacement	0.071	12	223,488	18,624	4	4
Residential Installment Payment Refrigerators	0.093	15	133,950	8,930	3	3
Commercial/Industrial Air Conditioner Tune-up	0.015	10	374,100	37,410	33	0
Commercial/Industrial Demand Response	0.025	10	525,000	52,500	175	175
Commercial Energy Efficient Lighting	0.040	10	1,134,000	113,400	23	12
Industrial Variable Speed Drives	0.018	15	1,033,200	68,880	14	7
Industrial Energy Efficient Motors	0.028	15	186,000	12,400	2	1
Portfolio Total			**9,315,738**	**743,544**	**418**	**455**

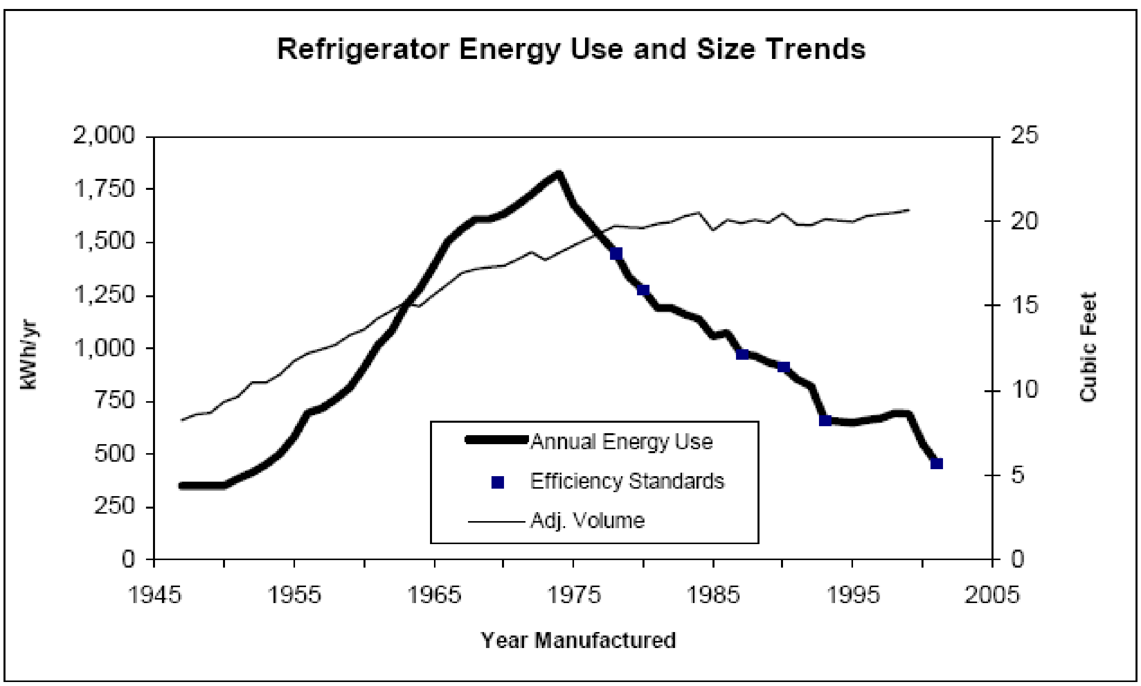
Refrigerator Replacement Programs

According to a report by the Natural Resource Defense Council (NRDC), over 30% of homes with annual income of $10,000 to $24,999 have a refrigerator that is 10 years or older.[22] Over 300,000 EKPC residential customers live in counties where the median household income is within this range, which creates the potential for replacement of more than 46,000 old, inefficient refrigerators.

The age of a household's refrigerator is important because electricity consumption of refrigerators has declined substantially since 1974 with new refrigerators consuming approximately 70% less than their peak.[23] Figure 1 shows the dramatic savings potential for the replacement of old refrigerators compared with new, higher efficiency ones.

Figure 1

Refrigerator Energy Usage



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22 Natural Resources Defense Council, *Out with the Old, In with the New: Why Refrigerator and Room Air Conditioner Programs Should Target Replacement to Maximize Energy Savings*, November 2001, Figure 9, p. 25.

23 Ibid., Figure 2, p. 7.

Utilities across the country have instituted refrigerator replacement programs to tap into this potential for energy savings. These programs are being delivered in large metropolitan areas and small municipalities alike.[24]

Recent studies show that the size of a typical refrigerator being replaced is 16 to 19 cubic feet with an average age of 18 years.[25] The savings estimates for refrigerator replacement programs vary widely from 663 kWh/year in a New York study to 1,327 kWh/year in an Iowa study. The Low-Income Retrofit Program in New Hampshire, for example, reveals that savings from program participants at a rural electric cooperative were 1,056 kWh/yr while the weighted average for all utilities across the state is 893 kWh/year.

In some cases, a recycling component is added to the program and the customer's old refrigerator is taken away by a qualified recycling center to have its components recycled in an environmentally friendly manner.

Installment Payment Refrigerator Program

Low-income households are not the only market segment that faces competing demands on their cash flows. Many residential customers are not able, or choose not to prioritize their spending to meet the up-front costs necessary to purchase energy efficient appliances, especially when there is remaining life on the existing ones. An innovative program called Pay As You Save, or PAYS®, has been successfully implemented by the distribution co-ops of the New Hampshire Electric Cooperative.

The main goal of an installment payment program similar to PAYS® is to advance the penetration of energy efficient equipment and appliances in households by helping consumers who lack capital and the inability or unwillingness to incur additional debt to acquire these energy-saving measures. This type of program is particularly well-suited to meet the barriers facing increased energy efficiency at rental properties. Tenants are frequently unwilling to invest in energy saving

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[24] Ibid., p. 27.

[25] Table 2.5 of the *Final Report: The New Hampshire Electric Utilities' Low-Income Retrofit Program, Impact Evaluation* (January 16, 2006) reveals 16 cubic feet as the average refrigerator size of program participants for all New Hampshire utilities with an average annual savings of 893 kWh. Another program sponsored by AmerenUE and not limited to low-income participants, reports an average size of 18 cubic feet with an average age of 18 years (2005 Missouri EnergyStar® Refrigerator Rebate and Recycling Program Final Report, p. 9).

measures as they may not stay at that premises long enough to realize a return on their investment. Landlords may be unwilling to make the investment because their tenants are responsible for payment of energy bills. This decision-making can lead to an untapped potential for energy efficiency.

In this program, installment payments for a new energy-efficient refrigerator are made monthly as part of the customer's electric bill. In the successful PAYS® program, the duration of installment payments are structured not to exceed three-fourths of the appliance life nor will the monthly payment amount be more than the expected average monthly bill savings. Bulk purchases of refrigerators for the program also lead to cost savings for all. In rental properties, landlords must agree in writing that they will inform future tenants of the continued responsibility to meet these payment obligations on their monthly electric bills.

A refrigerator replacement program with installment payments is recommended as part of this portfolio for EKPC. Replacing the old refrigerator of a customer of an EKPC member co-op can save nearly 900 kWh per year, translating into bill reductions totaling up to $80 per year at the current cost of electricity. As the cost of electricity increases, as it surely will considering EKPC's over-dependence on coal, the bill savings from replacing an old refrigerator will also increase.

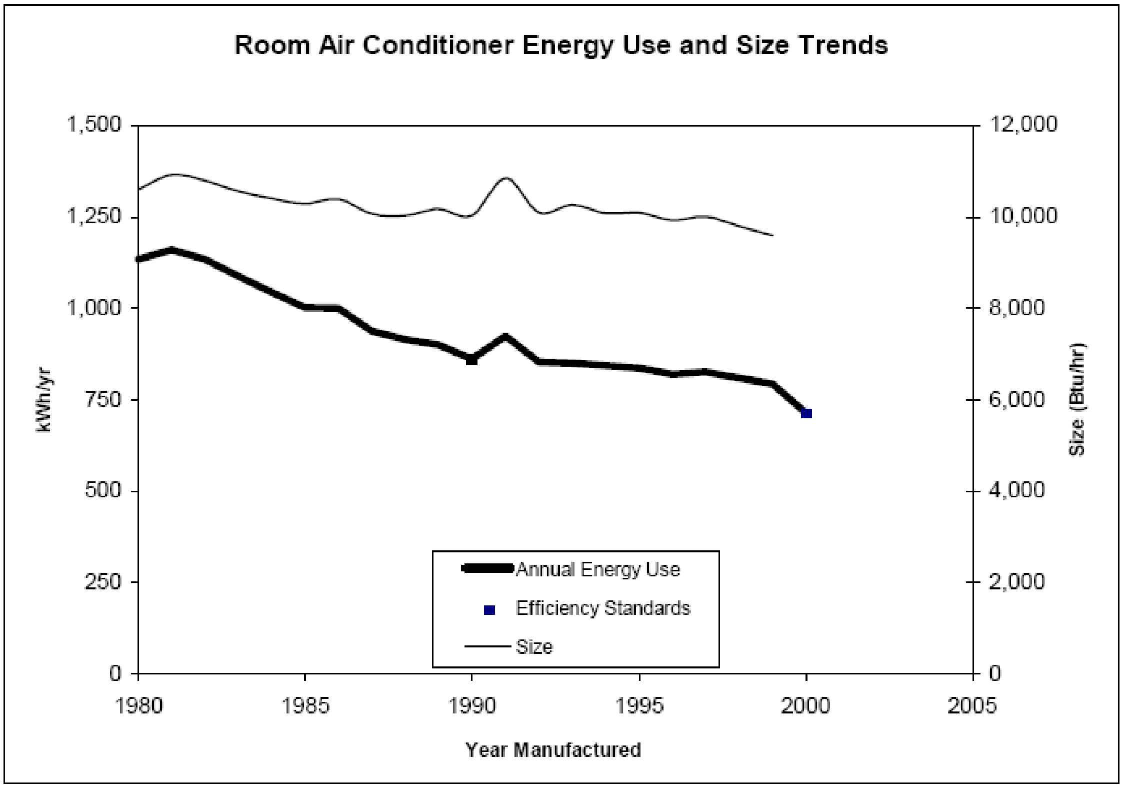
Room Air Conditioner Exchange Program

Room air conditioning units have also realized significant efficiency gains over the last two decades (see Figure 2).[26] Yet many low-income households cannot take advantage of the bill savings these new units would afford due to difficulty with cash flow or credit access.

A very successful program targeting low-income customers, one that may be particularly attractive in Kentucky, is the Room Air Conditioner Exchange Program. In this program, a co-op customer would exchange an old, inefficient room air conditioner for a new, EnergyStar model at no cost. Turn-in events are scheduled in the community, and customers must reserve one of a limited number of high-efficiency units available for trade. Prior to the trade-in event, a customer must provide information about his/her existing unit so that one of the same size can be made available at the event.

[26] Natural Resources Defense Council, *Out with the Old, In with the New*, Figure 1, p. 6.

Figure 2
Room Air Conditioner Use



In a replacement and recycling program conducted in New York, the average Energy Efficiency Ratio (EER)[27] of a room air conditioner replaced by participants was 8. By contrast, most EnergyStar room air conditioners today have a 10 to 11 EER, which means that the replaced units could be operating over one-third more efficiently. Previous program implementers have also found that units submitted for exchange were ill-maintained, so they concluded that actual savings may have been even higher than the engineering estimates, possibly reaching efficiency gains of nearly 50%.[28]

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[27] Energy Efficiency Ratio (EER) is a way to describe and compare the efficiency of air conditioning units and refrigeration compressors as it measures the relationship of equipment output in Btu/hr to electric input in kW.

[28] Natural Resources Defense Council, *Out with the Old, In with the New*, p. 21.

A 2006 room air conditioner exchange program in Chicago realized annual energy savings of 230 kWh per average unit where cooling seasons are shorter and may be less severe than states in the Central Southeast. In Kentucky, a room air conditioner exchange program can expect to achieve average annual energy savings of 300 kWh per unit at a cost of saved energy less than 6 cents/kWh.

The Midwest Energy Efficiency Alliance has assisted utilities in making this type of program a success.[29] To keep program costs low, volunteers from community-based nonprofit organizations supplemented the human resources provided by utilities. Another way to minimize program costs is to affiliate the program with a recycling center. Because materials such as copper, iron residue, and steel in the old air conditioners can be recycled, a utility may receive reimbursement to help offset a small portion of program costs.[30]

Since estimates show that 15% of households in Kentucky have at least one room air conditioner, there are thousands of old, inefficient air conditioning units available for replacement available across the state.[31] Therefore, should East Kentucky Power Cooperative provide an exchange program similar to ones in other Midwest states, it is reasonable to assume that 1,500 units could be replaced over ten years with a 4,500 MWh reduction in energy consumption annually.[32]

Residential Compact Fluorescent Lighting

Since a 20% energy savings in the residential sector can be achieved by adopting compact fluorescent lighting over incandescent lamps, any good energy efficiency portfolio contains a program to promote energy efficient residential lighting.

Lights for Learning, a program offered in conjunction with the Midwest Energy Efficiency Alliance, leverages the efforts of volunteers to maximize the

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[29] The Kentucky Department of Natural Resources is a member of the Midwest Energy Efficiency Alliance.

[30] ComEd, *2006 Room Air Conditioner Exchange Program Final Report*, p. 23.

[31] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, Table 4-15, p. 41.

[32] Energy savings represent the effects of cumulative program participation in the tenth year of the recommended energy efficiency portfolio. See Appendix Table A-4 for participation assumptions.

effectiveness of program delivery. In this program, compact fluorescent lights (CFLs) are sold as fundraising products through schools. Although it is not targeted at the low-income community, it can simultaneously achieve multiple goals. First, it helps local schools raise much-needed funds by allowing educational organizations to keep 50% of the profits. Second, it provides a low-cost way to educate people on the benefits of energy-efficient lighting in their homes. Third, the program allows households an easy and low-cost way to achieve energy savings while helping to meet the financial needs of their schools. By once again using volunteers to market the program and deliver the products, costs can be kept to a minimum.

EKPC could implement a similar program through both educational institutions and religious organizations to maximize the impact within the community. With 20,000 program participants annually, and each participant purchasing 3 compact fluorescent bulbs, EKPC can realize a savings of 60,000 MWh each year after the program is fully implemented in 10 years. Studies show that for CFLs used 6 hours per day, the cost of conserved energy is 1.2 cents/kWh, while those used 2 hours per day yield a cost of 2.3 cents/kWh.[33]

Programmable Thermostats with Utility Load Control Capability

Because summers in the East South Central region of the United States are 31% hotter than the U.S. average,[34] it's not surprising that Kentucky has a 76% penetration rate for central air conditioners.[35] However, the penetration rate for programmable thermostats in Kentucky households is only 19%.[36] In comparison, neighboring Illinois has a 47% penetration rate for programmable thermostats.[37] Installing programmable thermostats in single and multi-family dwellings can achieve substantial energy savings because residents don't have to remember to adjust the temperature settings for their space heating and cooling equipment when

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[33] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*.

[34] U.S. Department of Energy, Energy Information Administration, *Regional Energy Profile: East South Central Appliance Report 2001.*

[35] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, Table 4-15, p. 41.

[36] Ibid., Table 4-14, p. 40.

[37] Ibid.

they leave the premises or go to sleep. In addition to these obvious benefits, new technology now allows the utility to communicate directly with the customer's thermostat. The advantage of this new capability is that with the customer's permission, the utility can control the duty cycle of the central air conditioning compressor during periods of summer peak demand. This will enable fewer compressors to operate at the same time, thereby creating less peak demand on the EKPC system.

Load control devices such as these have been used for decades by investor-owned utilities and not-for-profit generation and transmission companies. Even in the early 1980s, Oklahoma Gas & Electric successfully controlled peak summer loads using a less sophisticated radio-controlled device. Wabash Valley Power Authority (WVPA), a not-for-profit generation and transmission company serving rural areas in Indiana, has also been using load control for well over two decades. WVPA has used load control as a mechanism to reduce customer demand at the most-costly, high-voltage service points, thereby avoiding ratchet penalties for wholesale power purchases.[38]

Air Source Retrofit Heat Pump Program

Another way to achieve significant benefits in energy efficiency is to convert inefficient electric space heating equipment to high-efficiency ground or air source heat pumps. With the exception of Missouri, Kentucky households, at a 20% penetration rate, use conventional electric space heating more than any other Midwest state studied by the Midwest Alliance for Energy Efficiency.[39] At 8%, its penetration of heat pumps is admirably the highest of these Midwest states, with Indiana a distant second at 5%. However, if the EKPC service area is representative of the state as a whole, there could be nearly 94,000 homes with significant energy savings potential. At a cost of conserved energy less than 2 cents per kWh, EKPC can administer a program, including incentives, to install air source heat pumps in 3,000 households per year. In addition to the incentives to help offset installation

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[38] Ratchet penalties are commonly applied to the billing demand of wholesale and large commercial/industrial retail power transactions that require the purchaser to pay a portion of their highest annual demand on every subsequent bill until a new demand is established in the following year.

[39] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, Table 4-14, p. 40.

costs, each program participant could realize $470 annually from their electric bill.[40] After 10 years at this level of program participation, EKPC could achieve 174,300 MWh in energy savings each year.

Residential Water Heater Replacement

Electric water heaters provide another source for electric energy savings. The MEEA estimates that 66% of Kentucky's electric water heaters operate at the minimum efficiency level.[41] Further, only 15% of water heaters in Kentucky have insulated tank wraps to decrease heat loss.[42] MEEA's study found that a 20% savings is attainable by installing thermal blankets to water heaters; wrapping pipes with insulation; and upgrading water heaters to higher efficiency models. They found that in the Midwest, the total cost of conserved energy for a high-efficiency water heater is 6.9 cents/kWh. With a slightly higher cost of conserved energy at 7.1 per kWh, EKPC can avoid generating over 18,000 MWh annually by replacing electric water heaters with new, high-efficiency models in a ten-year program.[43]

Energy Efficiency Options for Commercial and Industrial Customers

Although customers in the residential sector may live in multi-family dwellings or single family residences, including manufactured homes, their usage patterns and load characteristics are quite homogenous. However, the commercial customer class has much more diversity as it serves everything from the small retail boutique to the large hospital. This diversity in customer type carries with it a broad range of daily and annual usage patterns. Restaurants demand more electricity during meal times when cooking equipment is heavily utilized and cooling load increases. Schools see a drop in the need for electricity during the summer.

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[40] This value assumes 5,810 kWh savings per year at the median residential electric rate for all EKPC distribution companies.

[41] Midwest Energy Efficiency Alliance, *Midwest Residential Market Assessment and DSM Potential Study*, Table 4-16, p. 43.

[42] Ibid.

[43] The cost of conserved energy in the Midwest is 6.9 cents/kWh per the *Midwest Residential Market Assessment and DSM Potential Study*, p. 7, commissioned by the Midwest Energy Efficiency Alliance.

Religious institutions typically experience spikes in electricity demand when their congregations meet.

Large industrial customers frequently have unique contracts with their power supplier listing the specific conditions and provisions of their power supply. Gallatin Steel, for example, receives electricity from EKPC through Owen Electric Cooperative. The 120 MW load requirements of its arc furnace are interruptible for as many as 360 hours per year. Gallatin also offers another 40 MW of its power requirements to be curtailed when the utility experiences periods of high system demand. In return, Gallatin is given credit on its monthly electric bill, as specified in the provisions of its contract. The compact between a utility and its customer that allows for the periodic curtailment of load is frequently referred to as demand response.

Commercial/Industrial Demand Response Programs

A demand response program aimed at commercial and industrial customers is an important part of a demand-side management portfolio because it helps defer or eliminate the need for an additional power plant by providing substantial reductions in demand at the time of the utility's system peak. It can be a good complement to other programs that offer high energy savings, but only minimal demand reductions coincident with the utility's system peak.

Demand response programs offer benefits in many ways. They allow the utility to provide credit on customers' bills instead of purchasing expensive power in the wholesale marketplace or generating power at peak demand periods. Further, demand response programs make use of available distributed generation resources within the service territory as customers transfer some or all of the electric requirements to their on-site generation facilities. They also offer increased system reliability because customers are under contractual obligation to reduce load when notified, in exchange for financial compensation.

For EKPC and its customers, the cost of saved energy from a commercial/industrial demand response program is $0.028 per kWh. This program, as modeled in the recommended portfolio is projected to show potential system energy savings of 52,500 MWh after 10 years with 5,000 participants. This represents approximately 17% of EKPC's commercial/industrial customers and a reduction of roughly 1% of the annual consumption of the commercial and industrial classes combined. Demand savings under such a program would reach 175 MW per year after 10 years and full program participation.

Commercial Industrial Lighting

Lighting in commercial and industrial buildings is a significant source of electricity usage. Table 5 below shows the percent of energy consumed by lighting in typical commercial building types.[44]

EKPC has designed a commercial/industrial lighting program providing generous financial incentives that should be offered by all EKPC distribution cooperatives and remain a part of a robust demand-side management portfolio with significant participation levels. If, after 10 years, approximately 50% of EKPC's commercial and industrial customers were to install energy-efficient lighting systems, over 113,000 MWh could be saved *each year.*

Table 5

Lighting Consumption as a Percentage of Total Building Energy Usage by Type

Building Type	Lighting as a Percent of Total Energy Consumed
Health Care	16%
Lodging	20%
Office	30%
Schools	19%

Commercial/Industrial Air Conditioner Tune-up Program

Space cooling requirements typically run between 5 to 10% of all energy use in commercial buildings.[45] Further, many of these air conditioning systems are operating at less than optimal levels, which means that it takes more energy to achieve and maintain the desired temperature. A cost-effective Commercial Air Conditioner Tune-up Program has been proposed in the 2005 Integrated Resource

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[44] U.S. Department of Energy, Building Technologies Program.

[45] U.S. Department of Energy, *Scenarios for a Clean Energy Future*, November 2000, p. 42.

Plan of Louisville Gas & Electric and Kentucky Utilities. In this program, commercial air conditioning units are examined and then services are provided at a discount to bring each space cooling system to its optimal operating level. EKPC is a good candidate for a similar program. With potential demand reductions of 2.2 kW per participant and nearly 2,500 kWh savings annually, this program can have a significant impact on EKPC's system load requirements. If about half of EKPC's commercial and industrial customers participated in the program, EKPC would realize a cumulative summer demand reduction of 33 MW and an energy savings of 37,410 MWh.

High Efficiency Motors and Variable Speed Drives

Motors are an important part of many businesses. They are essential in a wide array of applications from cold storage in grocery stores to manufacturing in large industrial facilities. Energy savings from these sources can result in substantial expense reductions for the customer. Identified by the U.S. Department of Energy as an example of best practices, a performance optimization project of Minnesota Mining and Manufacturing (3M) reduced electricity consumption by 41% and cut expenditures by $77,554 annually due to increasing the efficiency of approximately 1,000 electric motors at its main campus.[46]

In steel mills, fluid handling systems such as pumps, fans, and air compressors consume close to 40% of all motor energy and are strong candidates for cost saving opportunities.[47] EKPC along with Owen RECC should work closely with and provide incentives for Gallatin Steel, its largest customer, so that all parties can benefit from high-efficiency motors, and where applicable, variable speed drives (VSDs). With the cost of saved energy at 1.8 to 2.8 cents per kWh for installing high-efficiency motors and VSDs, it is worthwhile to pursue these types of programs as a way of achieving long-term expense reduction for the customer, and optimal system planning for the utility.

[46] U.S. Department of Energy, *Best Practices Technical Case Study*, May 2002.

[47] U.S. Dept. of Energy, Office of Industrial Technologies, *Improving the Energy Efficiency of Motor Systems*, December 2001.

RENEWABLE ENERGY PROGRAM OPTIONS FOR EKPC

In addition to investing in the kinds of energy efficiency and demand response programs discussed so far, EKPC must also invest in clean, renewable energy resources. Wind, solar, and small-scale hydroelectric can provide needed power without the harmful and costly attributes which accompany coal-fired generation. In fact, over *one million* MWh of power from renewable energy resources can be made available to EKPC and its member co-ops annually (see Table 6).

Table 6

Renewable Energy Program Recommended for East Kentucky Power Cooperative[48]

Renewable Energy Resource	Annual Generation (MWh)	Maximum Demand (MW)	Cost ($/kWh)
Residential Solar Water Heaters	24,530	11	$0.075
Commercial Solar Water Heaters	17,456	7	$0.053
Wind-Powered Generators[49]	192,720		$0.035
Hydroelectric Power	842,055	191.5	$0.036
TOTAL	1,076,761	209.5	$0.037

Residential and Commercial Solar Water Heater Programs

Solar water heating systems serve as a source of distributed power generation and a load reducing, demand-side-management tool. Solar water heating systems are in widespread use in many parts of the world, including the Unites States. While the U.S market for solar water heating is presently quite small, the global market grew by 14% in 2005, with worldwide installations reaching 46 million homes using technology that is mature and well-established.[50]

48 The total cost per kWh represents a weighted average based on the net costs for each resource.

49 Since wind is not a dispatchable electric generation source, it is common practice to exclude capacity values for demand planning purposes.

50 Http://www.environmentcalifornia.org/reports/energy/energy-program-reports/solar-water-heating-how-california-can-reduce-its-dependence-on-natural-gas.

Solar water heating systems are well-suited for residential domestic water heating; space heating; and many commercial, institutional, and industrial water heating applications. Common non-residential applications include swimming pool heating, laundromats, hotels, dormitories, multi-family dwellings, restaurants, food processing facilities, schools, and fire stations.

Systems typically operate for at least 25 years. A solar water heater provides the owner with a fixed cost for water heating energy, providing security against future energy price increases. This is especially important for customers of utilities like EKPC that face an extraordinary “carbon risk” when greenhouse gases are eventually regulated.

Solar water heating systems in Kentucky can typically meet 50–80% of a home’s domestic hot water needs on an annual basis. Systems are normally installed with a back-up heating system to ensure that hot water is always available. Systems are also designed with freeze protection so they can operate through the winter without trouble. For larger, non-residential (or multi-family/dormitory) facilities, the portion of energy provided by the solar thermal system will depend upon the system design and economic considerations, and can range from 25–80%, depending upon the circumstances. In both residential and commercial applications, solar water heaters offer the highest demand savings in the summer, during the utility’s peak demand periods on hot afternoons. At these times solar water heating systems are operating and avoid the use of electric heating elements.

Using data from East Kentucky Power Company’s Integrated Resource Plan, the typical residential customer consumes 4,821 kWh per year for water heating. A solar water heating system using a 40 square foot solar collector on such a home will save approximately 2,453 kWh per year. Such a system could be equipped with a single hot water storage tank that includes a back-up heating element, or could use two storage tanks, one to store solar-heated water and the other using the back-up heating element.

Table 7 shows the expected energy production and financial analysis for a typical residential solar water heating system. Maintenance requirements are relatively low and maintenance costs are small relative to the annual and long-term financial savings generated by the systems. The lifecycle operating and maintenance (O&M) costs represent periodic parts replacement, including the hot water storage tank, a pump, and the non-toxic antifreeze used in the solar plumbing. The solar thermal collector itself should require no servicing during the first 25 years of operation. As shown, a residential solar water heater will save its owner 61,325 kWh during the first 25 years of operation, at a cost to the customer of $0.055/kWh. This cost is significantly below the 2006 retail residential rate for all of the distribution cooperatives serviced by EKPC and will be even more so at the end of the life of a solar water heater.

Table 7

Residential Solar Water Heater
Energy and Financial Savings per Participant

Annual Energy Savings	2,453 kWh
Lifecycle Energy Savings (25 years)	61,325 kWh
Installed Cost	$4,500
Lifecycle Operating & Maintenance Costs	$1,000
EKPC Rebate	$1,104
Federal Tax Credit	$1,019
Final Lifecycle Cost to Participant	$3,377
Final Purchase Price to Participant	$2,377
Lifecycle Cost of Energy Savings to Participant, after incentives	$0.055/kWh

Note that even without the federal tax credit, the lifecycle cost of energy savings to participants will be $0.072 cents per kWh. This is still less than the current retail rate for electricity from all of EKPC's distribution cooperatives and it is a fixed price over the 25 years of the solar water heating system, whereas the retail rate of electricity from the distribution cooperatives will surely increase substantially in the next 25 years.

Commercial-scale solar water heating systems can generate and save many times more energy than a residential system. Table 8 shows the expected energy savings from a solar water heating system on a medium-sized commercial scale project, such as a laundromat or 50-bedroom hotel. The average hot water demand for such a facility is estimated to be 30,000 kWh/year. A solar water heating system with 320 square feet of solar thermal collectors would save 17,456 kWh/year. The estimated installation cost for such a solar water heating system is $24,000, and the 25-year lifecycle operations and maintenance costs are estimated at $3,600.

Table 8 also shows that a commercial solar water heating system of this size would save the customer 436,400 kWh during the first 25 years of operation and would produce energy savings at a cost of $0.034/kWh. Again this is significantly below the 2006 cost of electricity for commercial customers of all EKPC member co-ops, and may be dramatically below the cost 25 years from now.

Table 8

Commercial Solar Water Heater
Energy and Financial Savings per Participant

Annual Energy Savings	17,456 kWh
Lifecycle Energy Savings (25 years)	436,400 kWh
Installed Cost	$24,000
Lifecycle Operating & Maintenance Costs	$3,600
EKPC Rebate	$7,855
Federal Tax Credit	$4,843
Final Lifecycle Cost to Participant	$14,901
Final Purchase Price to participant	$11,301
Lifecycle Cost of Energy Savings to Participant, after incentives	$0.034/kWh

Even without the federal tax credit, the lifecycle cost of energy savings to participants still comes out to 4.5 cents per kilowatt-hour. This is still less expensive than the 2006 commercial and industrial rates of all EKPC's distribution cooperatives, except one, which was 4.42 cents per kWh. It is difficult to imagine a scenario in which the 4.5 cents per kilowatt-hour will not be a fraction of industrial and commercial rates two decades from today when the solar hot water system is still providing hot water.

A residential solar water heater program could achieve annual energy savings of 24,530 MWh in its tenth year with 10,000 participants (only 2% of EKPC's residential customer base). The summer demand reduction from this program would be 11 MW. A commercial solar water heater program with 1,000 participants could achieve 17,456 MWh in annual energy savings in its tenth year, with a 7 MW summer demand reduction.

Twenty-three states offer utility-based or state-sponsored financial incentives such as rebates, grants, tax credits, and low- or zero-interest loans for solar water heater installations.[51] Some programs offer a flat dollar amount back to the customer, regardless of the size or cost of the solar energy system. Others offer a percentage of the installed system cost. Some states have started to use performance-based incentives, which calculate the value of the incentive on the expected (or measured) energy output from the system. Performance-based incentives encourage system designs that emphasize energy savings and avoid the risk of contractors over-sizing or over-pricing systems simply to generate larger rebates. They also allow larger systems to reap proportionally larger incentives in contrast to programs that offer flat dollar amounts.

The program recommended for EKPC is a performance-based incentive based on the projected annual kilowatt-hour savings for the solar water heating system. For both residential and commercial customers, the incentive value is \$0.45 per kWh saved during the first year of operation. An incentive at this level would cover roughly 25% and 33% of the equipment and installation cost respectively for residential and commercial customers.

In addition to these rebates, low- or zero-interest loans or a "Pay As You Go" program should also be used to further mitigate the financial barrier presented by the up-front capital cost of such systems. Similar to the PAYS® program discussed earlier in this paper, the utility pays for the full installation of the solar water heating system and then adds a charge to the utility bill each month until the solar water heating system is paid off. For residential units, if the loan term or payment plan is over 15 years, the customer will see immediate reductions in their expenses as energy savings exceed the value of the monthly payments. For commercial customers, a loan or payment term of ten years would provide immediate savings in monthly expenses for the customer.[52]

Small Scale Hydroelectric Generation

Kentucky's abundance of rivers has the potential to provide clean and economical power from a proven technology. Yet, many of these sites remain undeveloped. The Kentucky River Authority owns sites with estimated generation

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[51] These states are Arizona, California, Delaware, Florida, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Missouri, New Hampshire, New York, North Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, Texas, Utah, Vermont, and Washington (http://www.dsireusa.org).

[52] This is based on a current electricity rate of \$0.07 per kWh.

capacity of 19.5 MW, while sites controlled by the Army Corps of Engineers could account for an additional 172 MW, bringing the total to 191.5 MW of power waiting to be tapped. To construct hydroelectric generation at all undeveloped sites in Kentucky would cost between $455 and $550 million.[53] With capacity factors ranging from 45–55%, these sites combined could produce a total of over 842,000 MWh annually at a median cost of $0.036 per kWh.[54] (See Appendix Table A-5 for detailed data.)

Wind Generated Power

As of September 2007, there were 16,819 MW of installed wind capacity in the United States with 3,506 more MW under construction. Nineteen percent of that installed capacity was built in 2006, demonstrating the rapid increase in the popularity of this generation source which has been driven largely by state renewable-energy portfolio standards and its increasing cost-effectiveness compared to fossil fuels. Texas alone has over 4,356 MW of installed wind-powered generating facilities. All states bordering on Kentucky have developed or are in the process of constructing wind resources. Appalachian Power Company, a subsidiary of American Electric Power (AEP) in West Virginia, recently signed a 20-year power purchase agreement for 75 MW of wind energy from the 150 MW Camp Grove Wind Farm in Illinois. During August 2007, AEP also announced that Indiana Michigan Power, another of its subsidiaries, had entered into a long-term agreement for 100 MW of capacity from Fowler Ridge Wind Farm in Indiana. Illinois has a total of 699 MW of installed wind power generating facilities with another 108 MW currently under construction.

Adding 100 MW of wind energy to an EKPC renewable energy portfolio would provide conservatively at least 192,720 MWh of clean energy to EKPC member cooperatives each year at a cost of approximately $0.035 per kWh.[55] These wind

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[53] Identification of potential hydroelectric generation sites, development costs, and capacity factors prepared by David H. Brown Kinloch of Soft Energy Associates, Louisville, Kentucky.

[54] Includes operation and maintenance expenses of $0.017 per kWh over the 30-year lifetime of the generation facility based on an average of O&M for Georgia Power hydroelectric generating plants, as reported in the Federal Energy Regulatory Commission Form 1, filed for 2006.

[55] A 22% capacity factor is assumed on a purchased power agreement at $0.06 per kWh, less $0.025 per kWh for the "green tag," that is the income from EKPC's green pricing program, Envirowatts. We are assuming $0.25 per kWh of the Envirowatts program would go to administrative costs.

projects could be developed at suitable sites in Kentucky or in other states, as many other utilities have done.

FUNDING OPPORTUNITIES FOR ENERGY EFFICIENCY AND RENEWABLE ENERGY PROGRAMS

Historically, energy efficiency programs have been funded through costs embedded in electric rates or through supplemental charges on electric bills. Programs were typically delivered by the utilities and their contractors or energy service companies. Today, however, there are a number of additional funding sources ranging from not-for-profit organizations to corporate foundations to state-sponsored energy grants and low-cost loans that can be used to support energy efficiency market transformation costs. For example, the Mountain Association for Community Economic Development (MACED), a nonprofit organization working in Eastern Kentucky and Central Appalachia, is launching a new initiative to provide affordable loans to Kentucky businesses to assist with the costs of installing energy efficiency measures. Such programs may provide fruitful partnering opportunities for EKPC.

In 2006, the Kentucky Solar Partnership (KSP) administered a pilot rebate program for residential solar water heaters, offering rebates worth $500. KSP had sufficient funding to provide 25 rebates, and all funds were committed in less than one year. In fact, KSP received 8 more applications than it had rebates. In addition, KSP is partnering with MACED to offer low-interest loans that cover the full cost of equipment and installation for solar water heaters and are repaid in monthly installments over six years.[56]

Another prime funding source is the Federal government, which allocates money to State Energy Offices, who in turn distribute funds for energy efficiency activities based on the priorities of each participating state. These programs have been very successful, and EKPC should consider partnering with the Kentucky State Energy Office to leverage these resources for their customers. A recent report of the National Association of State Energy Officials (NASEO) highlights some of the many success stories in other states that could be replicated in Kentucky.[57]

In Alabama, the School Retrofit Program provided $52,000 in energy efficiency improvements to 8 schools, resulting in energy cost savings of more than

[56] Http://www.dsireusa.org.

[57] National Association of State Energy Officials, *State Energy Program and Activity Update*, winter 2007.

$20,000 during the first year alone. In a second example, the South Carolina Energy Office reported that it had certified over 2,000 manufactured homes as energy efficient during fiscal year 2005-06. These homebuyers are able to reduce their monthly energy bills and qualify for an energy efficient mobile home tax credit. Through this and other State Energy Programs, South Carolina calculates that $17.40 in energy savings has been achieved for each federal dollar spent.

The Small Business $mart Energy Program in Illinois is one of the many State Energy Programs funded by the U.S. Department of Energy. It provides free technical assistance to a full range of businesses including groceries, restaurants, hotels, and assisted living centers. Thirty-six businesses have implemented some or all of the recommended energy improvements, saving an estimated 3.6 million kWh per year. In addition, the cost of saved energy has declined from $0.04 per kWh in 2005 to $0.01 per kWh in 2006.

Maine uses a portion of its federal funding to make loans for energy efficiency to small businesses. Each loan is capped at $35,000 with a current interest rate of 3%. Maine businesses are able to achieve electric savings of 561,466 kWh per year in addition to hundreds of thousands of therms of natural gas annually.

The U.S. Department of Energy is not the only federal source of funding for energy efficiency and renewable energy programs. On September 24, 2007, the U.S. Department of Agriculture announced that it selected 345 proposals in 37 states totaling $18.2 million for energy efficiency and renewable energy projects. EKPC should be particularly interested in this funding source because it targets agricultural producers and small rural businesses.

This is by no means a complete listing of all funding sources for programs involving energy efficiency and renewable energy. There are a wealth of nonprofit and public entities offering various forms of financial assistance. EKPC is encouraged to investigate all potential opportunities in order to leverage their resources, maximize program participation, and provide the cleanest and most fiscally responsible solutions to its customers.

CONCLUSION

EKPC can develop and implement a portfolio of energy efficiency programs at a lower cost than constructing, maintaining and operating a coal-fired power plant in this financially turbulent time. For an investment of less than $11 million dollars each year, EKPC can avoid the need to generate 743,544 MWh annually. The program life for most of the equipment and appliances recommended here is ten to twenty years, far beyond the ten-year implementation period of the portfolio, bringing the average cost of saved energy for the entire set of recommended programs to 2.4 cents per kWh.[58] Add to this a solar water heater program, combined with a 100-MW power purchase agreement for wind generation, and the development of undeveloped hydroelectric sites in the state, and there is no longer a need for a new coal-fired power plant. A key point worth repeating is that the portfolio of energy efficiency and renewable energy sources is flexible so that it can be tailored to meet the EKPC's electric needs if and when they arrive.

Table 9

Recommended Energy Efficiency & Renewable Energy Portfolio for East Kentucky Power Cooperative

	Annual Energy (MWh)	Maximum Demand (MW)	Cost ($/kWh)
Energy Efficiency Solutions	743,544	455	0.024
Renewable Energy Solutions	1,076,761	209.5	0.037
Total Energy Efficiency and Renewable Energy Portfolio	1,820,305	664.5	0.032

Through a committed effort to a portfolio of energy efficiency programs and the implementation of renewable energy resources, East Kentucky Power Cooperatives can defer or eliminate the need for its next planned coal-fired power plant and instead contribute to the long-term health and quality of life for its customers, Kentucky's citizens, and the environment.

[58] This analysis assumes a 4-year life for compact fluorescent lamps.

APPENDIX

Table A-1

Counties Fully or Partially Served by East Kentucky Power Cooperatives

County Name	% People Living in Poverty	County Name	% People Living in Poverty
Adair	21.5	Knott	27.0
Anderson	9.6	Knox	29.1
Barren	16.6	Larue	15.4
Bath	20.1	Laurel	20.4
Bell	28.8	Lawrence	24.8
Boone	7.7	Lee	29.8
Bourbon	14.3	Leslie	28.6
Boyle	14.8	Letcher	24.0
Bracken	12.8	Lewis	26.9
Breathitt	29.5	Lincoln	18.8
Breckinridge	16.3	McCreary	30.1
Bullitt	10.4	Madison	16.3
Campbell	10.9	Magoffin	29.9
Carroll	14.3	Marion	16.4
Carter	22.7	Martin	30.5
Casey	22.9	Mason	16.7
Clark	13.5	Meade	11.9
Clay	34.3	Menifee	24.2
Clinton	23.5	Mercer	13.6
Cumberland	22.1	Metcalfe	20.6
Edmonson	17.5	Montgomery	15.4
Elliott	25.3	Morgan	27.0
Estill	23.6	Nelson	12.9
Fayette	14.2	Nicholas	15.3
Fleming	17.8	Oldham	6.3
Floyd	26.8	Owen	16.0
Franklin	12.3	Owsley	35.5
Gallatin	17.2	Pendleton	13.6
Garrard	14.6	Powell	23.3
Grant	13.3	Robertson	19.0
Grayson	17.9	Rockcastle	21.4
Green	18.3	Rowan	20.7
Greenup	16.0	Russell	21.5
Hardin	13.0	Scott	10.5
Harlan	29.3	Shelby	11.0
Harrison	13.6	Spencer	9.3
Hart	20.5	Taylor	17.8
Henry	13.7	Trimble	14.1
Jackson	25.2	Washington	15.1
Jefferson	14.8	Wayne	24.3
Jessamine	13.2	Whitley	25.3
Johnson	23.3	Wolfe	29.4
Kenton	11.3	Woodford	9.6

Source: U.S. Census Bureau, Small Area Income and Poverty Estimates for Kentucky Counties, 2004

Table A-2

Energy Efficiency Portfolio Recommended for East Kentucky Power Cooperative

Program	Program Description	Targeted Customer Sector	Annual Energy Savings per Program Participant (kWh)	Summer Demand Savings per Program Particpant (kW)	Winter Demand Savings per Program Participant (kW)	Annual Number of New Participants	Cumulative Number of Program Participants	Annual Incremental Program Energy Savings (MWh)	Program Year 10 Cumulative Annual Energy Savings (MWh)	Cumulative Lifetime Energy Savings (MWh)	Cumulative Annual Summer Demand Savings (MW)	Cumulative Annual Winter Demand Savings (MW)	Cost of Saved Energy ($/kWh)
Air Source Heat Pump Retrofit	Offers incentives to customers who replace electric space heating equipment with high-efficiency air source heat pumps.	Residential Customers with Electric Space Heat	5,810	0.3	1.5	3,000	30,000	17,430	174,300	3,486,000	9	244	$0.017
Residential Lighting	Acts as a multi-purpose program that increases the penetration rate of compact flourescent lamps in households while raising money for schools by utilizing the efforts of school children and their families to take orders for and deliver CFLs to their families, friends & neighbors.	Residential	300	0.04	0.04	20,000	200,000	6,000	60,000	240,000	8	8	$0.018
Load Control Programmable Thermostat	Installs a programmable thermostat at a residential customer's location at no charge for the ability to remotely curtail the customer's air conditioner during periods of peak utility system demand.	Residential Customers with Central A/C	1,926	1.4	0	10,000	100,000	19,260	192,600	1,926,000	140	0	$0.018
Air Conditioner Exchange	Distributes new ENERGY STAR® qualified room air conditioners in exchange for old-inefficient ones at no cost to the customer.	Low-Income Residential	300	0.49	0	1,500	15,000	450	4,500	54,000	7	0	$0.058
Residential Water Heater Replacement	Replaces standard water heaters with high-efficiency water heaters	Residential Customers	388	0.09	0.09	4,800	48,000	1,862	18,624	223,488	4	4	$0.071
Residential Installment Payment Refrigerators	Provides consumers with energy efficient refrigerators without an up-front payment and payments made on monthy electric bills from bill savings.	Low-Income Residential	893	0.258	0.283	1,000	10,000	893	8,930	133,950	3	3	$0.093
Commercial/Industrial Air Conditioner Tune-up	Offers commercial customers an analysis of their existing air conditioning systems and discounted services on corrective action needed for the system to operate at maximum efficiency.	Commercial Customers	2,494	2.2	0	1,500	15,000	3,741	37,410	374,100	33	0	$0.015
Commercial/Industrial Demand Response	A program that offers financial incentives for a customer to reduce load to a pre-determined level during periods of high system demand.	Commercial & Industrial Customers	10,500	35	35	500	5,000	5,250	52,500	525,000	175	175	$0.025
Commercial Energy Efficient Lighting	Offers rebates for upgrading existing lighting in commercial establishments for energy efficient lighting systems.	Commercial & Industrial Customers	4,725	0.94	0.51	2,400	24,000	11,340	113,400	1,134,000	23	12	$0.040
Commercial/Industrial Variable Speed Drives	Offers technical assistance and rebates for variable speed drives to industrial and large commercial customers.	Industrial	98,400	19.4	10.7	70	700	6,888	68,880	1,033,200	14	7	$0.018
Commercial/Industrial Energy Efficient Motors	Offers rebates for replacement of existing motors with high-efficiency motors.	Industrial	12,400	2.4	1.3	100	1,000	1,240	12,400	186,000	2	1	$0.028
Program Portfolio Total								74,354	**743,544**	**9,315,738**	**418**	**455**	

Table A-3
Program Costs and Assumptions

Program Name	Annual Levelized Administrative Costs	EKPC Incremental Program Expenses	Total Utility Annual Program Costs	Comments
Residential Heat Pump	$2,500	$1,896,000	$1,898,500	Assumes $632 total cost per participant, including $182 per participant for marketing and related costs, and $450 in customer rebates. Costs from EKPC 2006 Integrated Resource Plan (IRP)
Residential Lighting	$1,000	$132,000	$133,000	This expense is $6.60 per participant, which assumes that EKPC subsidizes the cost of 3 bulbs per participant. Bulb costs at $2.20 each are from EKPC 2006 IRP.
Load Control Thermostat	$25,000	$3,500,000	$3,525,000	$350 per participant includes cost of customer acquisition and installing load control programmable thermostat at customer site. Costs based on estimates from EKPC 2006 IRP.
Air Conditioner Exchange	$15,000	$300,000	$315,000	Assumes $200 per new participant: Best Buy offers a 10,000 Btu A/C unit for $250, so a bulk discount is assumed. A levelized cost of $15,000/yr. covers marketing and customer contact. Similar programs in other service territories used many community volunteers on the actual exchange day to minimize costs.
Residential Water Heater Replacement	$5,000	$1,032,000	$1,037,000	Assumes $215 per new participant, with $65 per participant for marketing costs and customer communication, and $150 rebate to each participant per EKPC 2006 IRP.
Residential Installment Payment Refrigerators	$20,000	$225,000	$245,000	Assumes $225 per participant to assist with program paperwork and cover refrigerator delivery and finance charges. Marketing costs will come out of the $20,000/yr. administrative expenses.
Commercial A/C Tune-up	$25,000	$300,000	$325,000	This is based on a cost of $200 per new participant taken from the details of a similar program proposed in the LGE/KU IRP. The administrative cost of $25,000 per year assumes 20% of a full-time employee's time and other expenses to support program implementation.

Table A-3 (Cont'd)

Program Costs and Assumptions

Program Name	Annual Levelized Administrative Costs	EKPC Incremental Program Expenses	Total Utility Annual Program Costs	Comments
Commercial/Industrial Demand Response	$35,000	$687,500	$722,500	These amounts are based on a per participant cost of $1,375 for incentives to the customer. These numbers are from the EKPC 2006 IRP. Annual administrative costs for this program are estimated at $35,000 because it reflects the levelized cost of setting up a curtailment request infrastructure for software, communications, etc.
Commercial/Industrial Lighting	$20,000	$1,598,521	$1,618,521	These estimates are from the EKPC 2006 IRP. In addition to the $20,000 annual administrative costs, there will be $150 per new participant; average rebate to the customer based on EKPC current offer of $213 per kW load reduction at customer's site with a 90% system coincidence factor and $320 in lost revenues per program participant which would be recovered in rates as approved by the KY PSC.
Industrial Variable Speed Drives	$10,000	$689,500	$699,500	This amount assumes a payment of $0.10 per annual kWh saved to the customer plus a $10 per participant expense for administration, in addition to the annual administrative expense. A participant represents an average replacement of 100 horsepower of motors. Estimates from the EKPC 2006 IRP.
Energy Efficient Motors	$2,000	$300,000	$302,000	This assumes an average rebate to the participant of $3,000 based on a rebate of $5 per horsepower and customer will replace motors totaling more than 100 horsepower. Estimates from the EKPC 2006 IRP where it states that the rebate amount was determined based on review of other utility motor programs. The annual $2,000 administrative expense was also taken from the EKPC IRP.
Annual Total	**$160,500**	**$10,660,521**	**$10,821,021**	

Table A-4

Program Participation Rate Assumptions

Program Name	Annual Number of New Participants	Cumulative 10-Year Number of Participants	Assumptions
Residential Air Source Heat Pumps	3,000	30,000	EKPC served 469,121 residential customers in 2006 (see Table 1). A Midwest Energy Efficiency Alliance report estimates that 20% of Kentucky residences have electric space heating that is not heat pumps (see footnote 5), Therefore, there may be 93,824 households with the potential for converting electric resistance heat to air-source heat pumps. Additionally, assuming that less than one-third of this potential participates in the program over 10 years is quite reasonable.
Residential Lighting	20,000	200,000	This is an estimated amount that approximately 40% of EKPC customers would participate through a school fundraiser or through their religious organizations.
Residential Programmable Thermostats with Air Conditioner Load Control	10,000	100,000	EKPC served 469,121 residential customers in 2006 (see Table 1). A Midwest Energy Efficiency Alliance report estimates that 76% of Kentucky residences have central air conditioners (see footnote 35). Therefore, there may be 356,532 households with the potential for programmable thermostats that would also allow for EKPC direct load control of their central air conditioning units. Assuming that 28% of the 2006 number of EKPC's residential customers would participate over 10 years is quite reasonable.
Residential Room Air Conditioner Exchange	1,500	15,000	Room air conditioner penetration rate estimated at 15% of households (see footnote 31). Fifteen percent of EKPC's 469,121 residential customers assumes 70,368 households have at least one room air conditioning unit. Recommended program participation levels would result in the replacement of slightly more than 20% of room air conditioning units over 10 years.
Residential Water Heater Replacement	4,800	48,000	Penetration of electric residential electric water heaters in the EKPC service territory is 87%, which results in approximately 408,135 electric water heaters based on EKPC 2006 residential customers. Sixty-six percent of these operate at a minimum efficiency (see footnote 39). Therefore, there is a potential of replacing 269,369 water heaters for higher efficiency units. If 48,000 are replaced over 10 years as part of the program, it will represent approximately 18% of all electric water heaters.

Table A-4 (Cont'd)

Program Participation Rate Assumptions

Program Name	Annual Number of New Participants	Cumulative 10-Year Number of Participants	Assumptions
Residential Installment Payment Refrigerators	1,000	10,000	According to an NRDC report, over 30% of households with annual income levels between $10,000 and $24,999 have a refrigerator that is more than 10 years old (see footnote 22). Eleven EKPC member cooperatives partially or fully serve counties that have median household incomes less than $25,000 annually. The total number of customers served by these eleven co-ops is 309,543 in 2006. If half of these customers have an annual income less than $25,000 per year, then there could be as many as 46,431 refrigerators that are over 10 years old. A total of 10,000 replaced as part of this program represents about 21% of the estimated older refrigerators in low-income households.
Commercial/Industrial Air Conditioner Tune-up	1,500	15,000	There are a total of 46,431 commercial and industrial customers served by EKPC member cooperatives according to numbers reported to the Kentucky Public Service Commission for 2006. Fifteen thousand program participants represent approximately 15% of the total number of commercial and industrial customers. Although the number of program participants may vary due to the large variance in the size and usage of the customers in these two classes, the typical energy and demand savings across all program participants is reasonable (see Table 1).
Commercial/Industrial Demand Response	500	5,000	Although there is great diversity among the types of customers that comprise the commercial and industrial classes, there are many opportunities for customers of all types to shed load during specified hours when system load is unusually high. The projected cumulative participation rate in Year 10 represents nearly 11% of EKPC's 2006 total number of commercial and industrial customers.
Commercial/Industrial Lighting	2,400	24,000	Virtually all commercial customers have opportunities to reduce energy usage from lighting sources by switching to high-efficiency lighting products. Therefore, a 10-year cumulative program participation of 24,000, which represents nearly 52% of existing customers, is not unreasonable.
Industrial Variable Speed Drives	70	700	Applications of variable speed drives are frequently implemented at industrial customer sites. For EKPC, this would represent 50% of their 2006 industrial customer class. But these applications can be implemented at large commercial customer sites as well.
Commercial/Industrial Energy Efficiency Motors	100	1,000	Assumes replacement of motors for all applications in both commercial and industrial sectors totaling 20,000 horsepower per year. These applications may include motors used for fans, compressors, pumps, and material handling and processing operations. Program participants may come from a wide range of market sectors such as grocery stores, schools, and health care facilities; as well as manufacturing facilities including, but not limited to, steel-making operations.

Table A-5

Potential Hydroelectric Sites in Kentucky

Name	Water Source	Generation Potential (MW)	Site Owner	Development Status	Estimated Capacity Factor (%)	Estimated Development Cost ($/kW)	Annual Energy Production (kWh)	Minimum Investment and O&M ($/kWh)	Maximum Investment and O&M ($/kWh)
KY River L&D 5	Kentucky River	2	KY River Authority	No Development	50	2000–2500	8,760,000	0.032	0.036
KY River L&D 6	Kentucky River	1.5	KY River Authority	No Development	50	2500–3000	6,570,000	0.036	0.040
KY River L&D 8	Kentucky River	2	KY River Authority	No Development	50	2000–2500	8,760,000	0.032	0.036
KY River L&D 9	Kentucky River	2	KY River Authority	No Development	50	2000–2500	8,760,000	0.032	0.036
KY River L&D 10	Kentucky River	2	KY River Authority	No Development	50	2000–2500	8,760,000	0.032	0.036
KY River L&D 11	Kentucky River	2.5	KY River Authority	No Development	55	2000–2500	12,045,000	0.031	0.034
KY River L&D 12	Kentucky River	2.5	KY River Authority	No Development	55	2000–2500	12,045,000	0.031	0.034
KY River L&D 13	Kentucky River	2.5	KY River Authority	No Development	55	2000–2500	12,045,000	0.031	0.034
KY River L&D 14	Kentucky River	2.5	KY River Authority	No Development	55	2000–2500	12,045,000	0.031	0.034
Meldahl L&D	Ohio River	80	US Army COE	License Application	55	2000–2500			
Myer L&D	Ohio River	60	US Army COE	No Development	50	2500–3000	262,800,000	0.036	0.040
Newburgh L&D	Ohio River	60	US Army COE	No Development	50	2500–3000	262,800,000	0.036	0.040
Nolin River Lake	Nolin River	5	US Army COE	No Development	50	2000–2500	21,900,000	0.032	0.036
Rough River Lake	Rough River	4	US Army COE	No Development	50	2000–2500	17,520,000	0.032	0.036
Barren River Lake	Barren River	5	US Army COE	No Development	50	2000–2500	21,900,000	0.032	0.036
Cave Run Lake	Licking River	5	US Army COE	No Development	50	2000–2500	21,900,000	0.032	0.036

Table A-5 (Cont'd)

Potential Hydroelectric Sites in Kentucky

Name	Water Source	Generation Potential (MW)	Site Owner	Development Status	Estimated Capacity Factor (%)	Estimated Development Cost ($/kW)	Annual Energy Production (kWh)	Minimum Investment and O&M ($/kWh)	Maximum Investment and O&M ($/kWh)
Carr Fork Lake	Carr Fork	1.5	US Army COE	No Development	50	2500–3000	6,570,000	0.036	0.040
Taylorsville Lake	Salt River	2	US Army COE	No Development	50	2500–3000	8,760,000	0.036	0.040
Buckhorn Lake	Middle Fork KY River	2	US Army COE	No Development	50	2500–3000	8,760,000	0.036	0.040
Fishtrap Lake	Levisa Fork	2	US Army COE	No Development	50	2500–3000	8,760,000	0.036	0.040
Yatesville Lake		2	US Army COE	No Development	50	2500–3000	8,760,000	0.036	0.040
Dewey Lake	John's Creek	1.5	US Army COE	No Development	50	2500–3000	6,570,000	0.036	0.040
Paintsville Lake	Paint Creek	1.5	US Army COE	No Development	50	2500–3000	6,570,000	0.036	0.040
Grayson Lake	Little Sandy River	2	US Army COE	No Development	50	2500–3000	8,760,000	0.036	0.040
KY River L&D 1	Kentucky River	1.5	US Army COE	No Development	45	2500–3000	5,913,000	0.038	0.042
KY River L&D 2	Kentucky River	1.5	US Army COE	No Development	45	2500–3000	5,913,000	0.038	0.042
KY River L&D 3	Kentucky River	1.5	US Army COE	No Development	45	2500–3000	5,913,000	0.038	0.042
KY River L&D 4	Kentucky River	2	US Army COE	No Development	50	2000–2500	8,760,000	0.032	0.036
Green River L&D 1	Green River	1.5	US Army COE	No Development	45	2500–3000	5,913,000	0.038	0.042
Green River L&D 2	Green River	1.5	US Army COE	No Development	45	2500–3000	5,913,000	0.038	0.042
Green River L&D 3	Green River	2	US Army COE	No Development	50	2000–2500	8,760,000	0.032	0.036

Table A-5 (Cont'd)

Potential Hydroelectric Sites in Kentucky

Name	Water Source	Generation Potential (MW)	Site Owner	Development Status	Estimated Capacity Factor (%)	Estimated Development Cost ($/kW)	Annual Energy Production (kWh)	Minimum Investment and O&M ($/kWh)	Maximum Investment and O&M ($/kWh)
Green River L&D 5	Green River	2.5	US Army COE	No Development	55	2000-2500	12,045,000	0.031	0.034
Green River L&D 6	Green River	2	US Army COE	No Development	50	2000-2500	8,760,000	0.032	0.036
Barren River L&D 1	Barren River	2.5	US Army COE	No Development	55	2000-2500	12,045,000	0.031	0.034
Green River Lake	Green River	5	US Army COE	Preliminary Permit	50	2000-2500			
Cannelton L&D	Ohio River	80	US Army COE	Under Development	55	2000-2500			
Smithland L&D	Ohio River	90	US Army COE	Under Development	55	2000-2500			
	Total	**191.5**					**842,055,000**	**Median Cost ($/kWh)**	**0.036**

About the Authors

Susan M. Zinga has twenty-five years experience working with a variety of organizations involved in the electric and natural gas industries in the United States, Europe, and Asia. Her breadth of experience includes projects for federal and state regulatory agencies; municipal and state-regulated utilities; service providers operating in a deregulated marketplace; and nonprofit organizations focused on environmental concerns.

Ms. Zinga was employed as the Director of Energy Policy at Southface Energy Institute, a nonprofit organization promoting renewable energy, "green pricing," and energy efficiency. In addition to her many responsibilities, she participated as a technical expert to the members of Georgia Governor Barnes' Energy Task Force, and was a leader in determining the statewide techno-economic potential for energy efficiency. She also worked directly with U.S. Secretary of Energy Spencer Abraham, as well as Assistant Secretary David Garman, on complex energy issues confronting the southeastern United States.

Her experience also includes a leadership role on the pricing team at MEAG Power, a wholesale electric generation and transmission corporation made up of 48 municipalities across Georgia; serving as a manager at Energy Management Associates (later a division of EDS), where she led projects for several domestic and international utilities; employment with PSI Energy, an investor-owned electric utility in Indiana; and working with the Indiana Utility Regulatory Commission as a member of a specialized team of experts formed by legislative mandate to produce independent energy forecasts for Indiana electric utilities. In addition to constructing econometric models for forecasting purposes, she provided written and oral testimony in regulatory proceedings on economic, financial, and prudency issues. She was also charged with authoring multiple reports for Governors Orr and Bayh examining the wholesale power marketplace within the state.

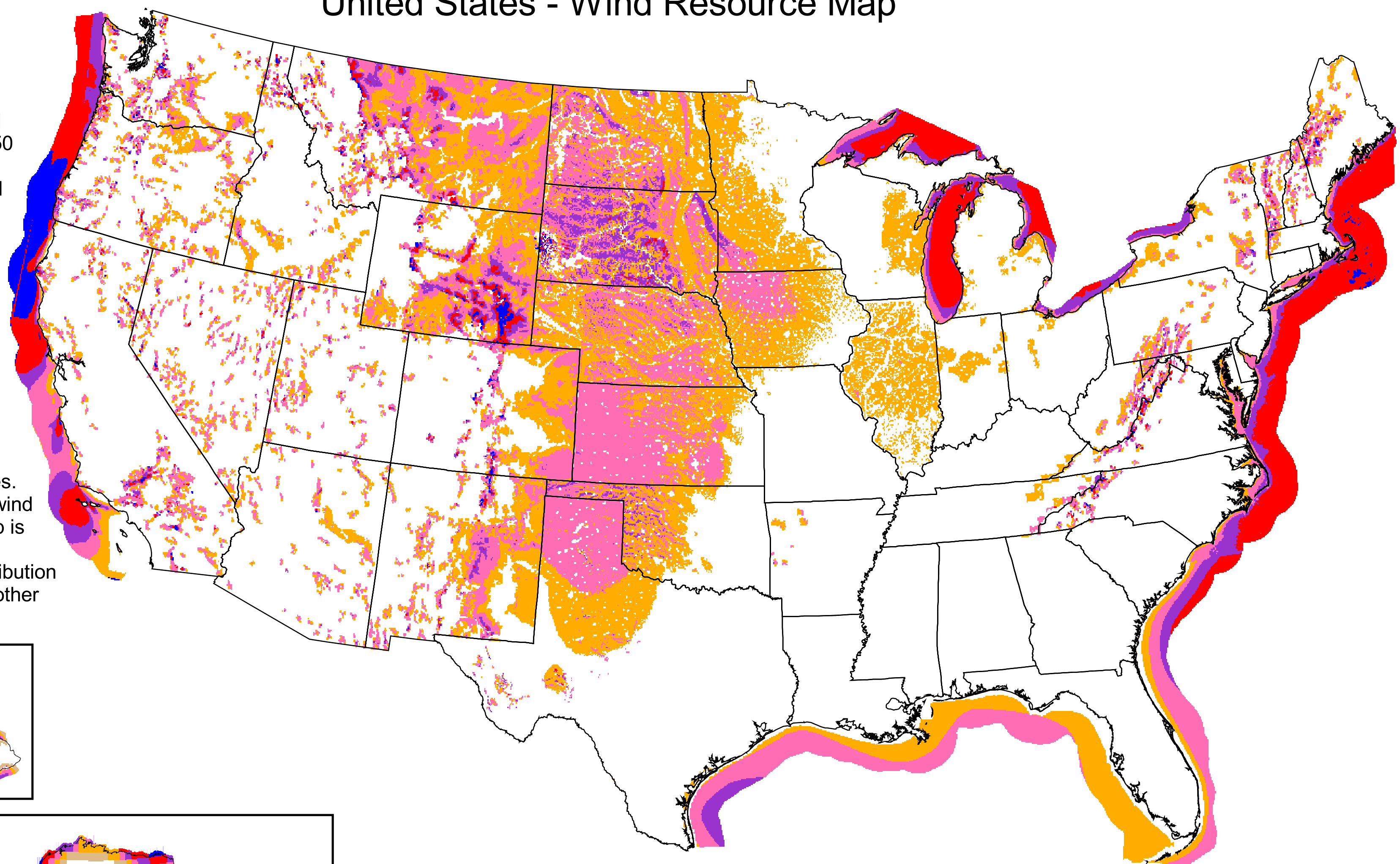
Ms. Zinga holds two degrees from Purdue University: a Master of Science in Public Policy and Public Administration with a concentration in Economics, and a Bachelor of Arts in Political Science.

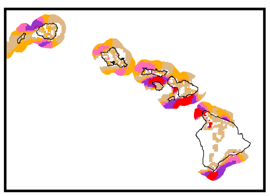
Andy McDonald is author of the solar hot water section of this report. Andy is the coordinator of the Kentucky Solar Partnership, a project of the nonprofit organization Appalachia—Science in the Public Interest, and co-author of *The Kentucky Solar Energy Guide*, published in 2005. He has a Master's Degree in Sustainable Systems from Slippery Rock University of Pennsylvania (2003), and a Bachelor of Arts in Philosophy from the University of Buffalo (1992). He is a co-founder and Chair of the Kentucky Solar Energy Society.

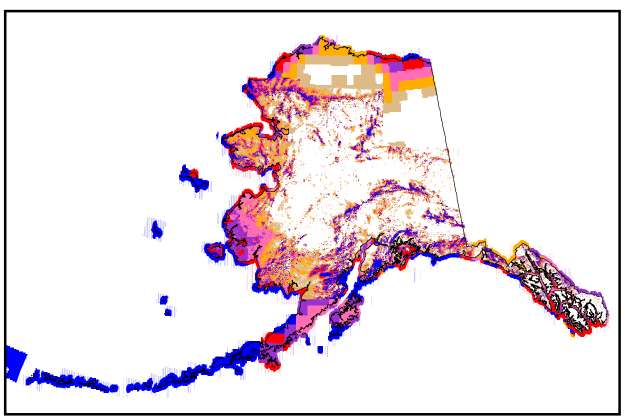
Andy has been working to promote a socially just, sustainable society for over fifteen years and has worked on sustainable development projects in Kentucky, Pennsylvania, the Texas-Mexico border, and Peru. He lives with his wife and step-daughter on a farm in Franklin County, where his wife operates an organic market garden.

United States - Wind Resource Map

This map shows the annual average wind power estimates at 50 meters above the surface of the United States. It is a combination of high resolution and low resolution datasets produced by NREL and other organizations. The data was screened to eliminate areas unlikely to be developed onshore due to land use or environmental issues. In many states, the wind resource on this map is visually enhanced to better show the distribution on ridge crests and other features.







Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

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Power Plant Emissions: Particulate Matter-Related Health Damages and the Benefits of Alternative Emission Reduction Scenarios

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Power Plant Emissions: Particulate Matter-Related Health Damages and the Benefits of Alternative Emission Reduction Scenarios

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Power Plant Emissions: Particulate Matter-Related Health Damages and the Benefits of Alternative Emission Reduction Scenarios

1 Introduction

Power plants are significant emitters of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). In many parts of the country, especially the Midwest, power plants are the largest contributors. These gases are harmful themselves, and they contribute to the formation of acid rain and particulate matter. Particulate matter (PM) reduces visibility, often producing a milky haze that blankets wide regions, and it is a serious public health problem. Over the past decade and more, hundreds of studies worldwide have linked particulate matter to a wide range of adverse health effects in people of all ages, including premature death, chronic bronchitis, hospital admissions and asthma. While this large body of research cannot establish a cause-and-effect relationship between PM and adverse health effects, the research does provide strong evidence that reducing ambient PM concentrations will lead to improvements in human health. The US EPA developed analytical methods that draw on this health research, combined with estimates of future air pollution emissions and air quality models, to prepare quantified estimates of the avoidable health effects from improving ambient PM levels. The EPA used these analytical methods to estimate the health benefits of a wide variety of actual or proposed individual federal air programs, including programs that reduce emissions from power plants, cars, and both on-road and off-road diesel engines.

This report estimates the avoidable health effects of each of a series of alternative regulatory scenarios for power plants, focusing on the adverse human health effects due to exposure to fine particulate matter ($PM_{2.5}$, which are particles less than 2.5 microns in diameter). This report uses the same analytical methods that the U.S. Environmental Protection Agency used in 2003 to prepare an analysis of the potential health effects of the proposed Clear Skies Act (EPA 2003). This report conducts an analysis of the impacts in 2010 and 2020 of three policy alternatives to the proposed Clear Skies Act:

- Carper/Gregg/Chaffee "The Clean Air Planning Act", S. 834 (henceforth "Carper")
- The Jeffords/Lieberman/Collins "The Clean Power Act", S. 366 (henceforth "Jeffords")
- The EPA August 2001 Straw Proposal (one of several alternatives EPA analyzed prior to the announcement of the Clear Skies Initiative in 2002). Henceforth "Straw"

For comparison purposes, this report includes the results of the EPA 2003 analysis of the Clear Skies Act (henceforth "CSA").

In addition, this report also examines the health impacts associated with the total amount of emissions from coal fired electricity generating units (power plants) in 2010. This "No EGU" analysis is clearly not a policy option, but rather helps gain a better understanding of the total magnitude of the health effects associated with the total emissions from this major sources of pollutants that lead to the formation of PM. It also helps put into better context the health improvements associated with each of the policy option scenarios examined in this report.

Following the methods used in the 2003 EPA analysis of the proposed Clear Skies Act, this study estimates the health impacts from various policy options for reducing power plant air pollution emissions. Using the same emissions estimates and air quality forecasting methods as EPA used in the

Clear Skies Act analysis, we prepare detailed future ambient air quality estimates for each of the nine scenarios described above. We then used the same health assessment methods as EPA to estimate the avoidable health effects associated with the changes in ambient air quality. Because we used the same methods and data as the 2003 EPA analysis, the results here are directly comparable with EPA's estimates of the future baselines for 2010 and 2020, as well as EPA's estimates of the potential improvements if the proposed Clear Skies Act is implemented. EPA has made extensive details of the technical details of their analysis available via the internet at www.epa.gov/clearskies/technical.html. The technical background materials on the methods and data sources for the EPA analysis are applicable to this analysis. In particular, the background paper on the models used in the EPA analysis ("Section H: 2003 Summary of the Models Used for this Analysis", at www.epa.gov/clearskies/03technical_package_sectionh.pdf) contains many details concerning the models used to estimate the electricity generation (IPM™), air quality (REMSAD) and the health analysis model (BenMAP) in both the EPA analysis and this report.

Chapter 2 describes the emissions inventory estimates, and the changes in the emissions associated with each scenario analyzed. Chapter 3 describes the methods used to estimate changes in particulate matter concentrations. Chapter 4 describes general issues arising in estimating and valuing changes in adverse health effects associated with changes in particulate matter. Chapter 5 describes in some detail the methods used for estimating and valuing adverse health effects, and in Chapter 6 we present the results of these analyses. Chapter 7 presents estimates of the impact of these alternative policy options on the PM non-attainment status.

This study has several appendices. Appendix A presents a derivation of the particulate matter concentration-response functions used in all the analyses. Appendix B presents additional detail on the results in Chapter 6, including statistical uncertainty analysis. Appendix C presents additional details about the non-attainment analysis in Chapter 7.

2 Emissions Inventory

The detailed estimates of the future emissions inventory used in this analysis is the same inventory EPA used in their analysis of the Clear Skies Act. In order to conduct an analysis of changes in the levels of ambient PM2.5 in the atmosphere from changes in emissions from power plants, it is necessary to have an estimate of the complete inventory from all sources of precursor emissions, not just the emissions from the source categories. EPA prepared the complete estimated emissions inventory for both 2010 and 2020 necessary to conduct a PM air quality analysis. This inventory includes emissions from not only power plants, but also other large industrial sources, all mobile sources, smaller "Area" emission sources ranging from gasoline stations to household emissions, agricultural emissions, and naturally occurring emissions from forests, grasslands, etc. The location and timing of emissions have an important impact on PM formation, so the emissions inventory includes extensive detail on the location and timing of the estimated emissions. Canadian and Gulf of Mexico sources are included in the inventory as well, as these pollutants effect PM levels in the continental US.

The emissions inventory estimates the quantity of emissions of six pollutants that will occur in specific future years (2010 and 2020 in this analysis) as future base case. For many emission source categories these future base cases have lower emissions in the future than occur now, as the impact of already enacted federal and state programs will increase over time. In particular, as older cars and trucks are replaced with newer, cleaner, vehicles the emissions from mobile sources decreases. Similarly older industrial equipment will be replaced by cleaner new equipment. In aggregate, total emissions are lower in the future base cases than in the 2001 emission inventory. Eventually, however, the improvements from existing programs will diminish as the programs are fully implemented. In addition to the forces that will decrease emissions , there are also forces that will increase emissions. Both a growing population and expanding economy tend to increase emissions. These forces generally grow stronger over time. Eventually the decreasing emissions from existing federal programs are overwhelmed by the increasing emissions from growth, and the total amount of emissions begins to increase.

Modeling the emission from power plants ICF Consulting used the IPM™ to forecast emissions from power plants for the policy options examined in this report. ICF Consulting used the same version of IPM™, with the same data and modeling assumptions, for the analysis in this report as they used for EPA's analysis of the Clear Skies Act.

IPM™ is an industry-leading energy modeling system that simulates the deregulated wholesale market for electricity. The EPA has used IPM™ to evaluate the economic, operational and emission impacts of a wide variety of policies and rulemakings affecting the power sector.

IPM™ is a multi-region linear programming model that determines the least-cost capacity expansion and dispatch strategy for operating the power system over specified future periods, under specified operational, market, and regulatory constraints. Constraints include emissions caps, transmission constraints, regional reserve margins, and meeting regional electric demand. Given a specified set of parameters and constraints, IPM™ develops an optimal capacity expansion plan, dispatch order, and air emissions compliance plan for the power generation system based on factors such as fuel prices, capital costs and operation and maintenance (O&M) costs of power generation, etc. Additional details about the EPA IPM™ model are available at EPA's Clear Skies Website, www.epa.gov/clearskies/technical.html.

The model is dynamic: it makes decisions based on expectations of future conditions, such as fuel prices, and technology costs. Decisions are made on the basis of minimizing the net present value of capital plus operating costs over the full planning horizon. The model draws on a database containing information on the characteristics of each power plant (such as unit ID, unit type, unit location, fuel used, heat rate, emission rate, existing emission control technology, etc.) in the U.S.

Summary of the National Emissions Inventory

There are six air pollutant emissions that are used to model PM concentrations. The are:

Oxides of Nitrogen (NOx)
Volatile Organic Compounds (VOC)
Ammonia (NH3)
Sulfur Dioxide (SO2)
Direct fine particle emissions (PM25)
Direct coarse particle emissions (PM10)
Primary Elemental Carbon (PMC)

Table 2.1 summarizes the estimated total emissions in the continental United States in 2010 for the six precursor air pollutants. Table 2.2 summarizes the total emissions in 2020.

Table 2.1 2010 Baseline Emissions Inventory (Tons/Year)

Source	NOx	VOC	NH3	SO2	PM10	PM2.5	PMC
EGU	3,943,438	32,660	1,783	9,856,926	217,623	109,983	107,640
Other Industrial	3,221,605	1,707,062	284,824	3,799,164	1,015,052	605,692	409,359
On Road	4,931,951	2,824,715	322,961	29,780	178,649	113,771	64,879
Non Road	3,409,824	2,016,276	49,964	252,924	286,189	243,085	43,104
Area	2,225,898	7,221,877	4,341,905	1,367,643	7,693,802	2,285,814	5,407,988
Total US	17,732,716	13,802,589	5,001,437	15,306,437	9,391,315	3,358,345	6,032,971
Canada & Gulf of Mexico	1,972,010	2,550,200	555,496	1,901,396	1,887,887	419,719	1,468,168
Total Modeled	19,704,726	16,352,789	5,556,933	17,207,833	11,279,202	3,778,064	7,501,139

Table 2.2 **2020 Baseline Emissions Inventory (Tons/Year)**

Source	NOx	VOC	NH3	SO2	PM10	PM2.5	PMC
EGU	4,056,026	35,389	1,478	8,956,475	227,727	116,895	110,832
Other Industrial	3,393,215	1,894,870	314,898	4,044,693	1,180,614	704,229	476,385
On Road	1,989,951	2,061,066	378,887	35,421	143,600	72,595	71,005
Non Road	2,842,794	2,192,851	59,548	228,308	227,336	186,359	40,977
Area	2,295,578	7,714,354	4,475,040	1,413,461	7,788,908	2,297,748	5,491,160
Total US	14,577,565	13,898,530	5,229,851	14,678,358	9,568,185	3,377,825	6,190,360
Canada & Gulf of Mexico	1,972,010	2,550,200	555,496	1,901,396	1,887,887	419,719	1,468,168
Total Modeled	16,549,575	16,448,730	5,785,347	16,579,754	11,456,072	3,797,545	7,658,528

Each of the policy options examined in this report keep hold the emissions constant from all emissions categories except for the EGU category. The EGU emissions in each policy scenario (including the Baseline scenarios) were modeled using IPM™, combined with additional methods developed by EPA to estimate the unit-specific emissions from each power plant unit. The IPM™ analysis incorporated the targeted emission caps for sulfur (SO2) and nitrogen (NOx) (as well as carbon and mercury if included in the scenario) from EGUs in modeling the emissions from each power plant. The targeted emission caps (referred to as the "nominal caps") are not necessarily met however, because of emissions trading provisions incorporated in each scenario. "Banking" of emission credits allows the modeled emissions to exceed the nominal caps in most policy option scenarios. Because the policy options provide power plant operators some discretion to "bank" emission reduction credits in one year by reducing emissions below that facility's mandatory levels, and in a later year use the banked credits as part of meeting their mandatory levels that year, the total emissions from power plants in a given year can exceed the nominal caps. Banked emission credits can also be sold, and used by another power plant operator. Banking is considered by the IPM™ model, so the air quality analysis (and subsequent health analysis) in both 2010 or 2020 can include emissions in excess of the nominal caps. The health effects estimated in this report therefore reflect the impact of the modeled emission changes, not the changes that would occur if the nominal emission caps are met.

In order to quantify the total contribution from all power plants in the No EGU analysis, we conducted the air quality analysis by eliminating the emissions from all fossil fueled electricity generation units, and calculate the resulting air quality. This identifies the total air quality "footprint" of power plants on fine particulate matter concentrations.

The nominal emission targets and the modeled emissions from electricity generating units are presented in Table 2.3

Table 2.3 Nominal and Modeled Emissions from Electricity Generating Stations

Scenario		Nitrogen	Sulfur
2010 Analysis			
Baseline	Modeled Emissions in 2010	3.9 million tons	9.9 million tons
Clear Skies Act	Nominal Cap	2.1 million ton cap by 2008	4.5 million ton cap by 2008
	Modeled Emissions in 2010	2.2 million tons	6.3 million tons
Straw Proposal	Nominal Cap	1.87 million tons by 2008	2 million ton cap by 2010
	Modeled Emissions in 2010	1.67 million tons	4.53 million tons
Carper Bill	Nominal Cap	1.87 million tons by 2008	4.5 million ton cap by 2009
	Modeled Emissions in 2010	1.83 million tons	4.77 million tons
Jeffords Bill	Nominal Cap	1.51 million tons by 2009	2.25 million ton cap by 2009
	Modeled Emissions in 2010	1.18 million tons	2.3 million tons
2020 Analysis			
Baseline Modeled	Modeled Emissions in 2020	4.06 million tons	8.96 million tons
Clear Skies Act	Nominal Cap	1.7 million ton cap by 2018	3 million ton cap by 2018
	Modeled Emissions in 2020	1.8 million tons	4.35 million tons
Straw Proposal	Nominal Cap	1.25 million ton cap by 2012	2 million ton cap by 2010
	Modeled Emissions in 2020	1.31 million tons	2.87 million tons
Carper Bill	Nominal Cap	1.7 million ton cap by 2013	2.25 million ton cap by 2016
	Modeled Emissions in 2020	1.76 million tons	3.39 million tons
Jeffords Bill	Nominal Cap	1.51 million tons by 2009	2.25 million ton cap by 2009
	Modeled Emissions in 2020	0.91 million tons	2.1 million tons

3 Air Quality Modeling

The analysis used results from the Regulatory Modeling System for Aerosols and Acid Deposition (REMSAD, ver 7.06) to forecast changes in the ambient concentration of both PM_{10} and $PM_{2.5}$ at the REMSAD grid cell level. Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, REMSAD is ideal for evaluating the air-quality effects of emission control scenarios.

Modeling future air quality anticipated to result from policy-driven emissions changes is extremely difficult and inherently uncertain. Alternative air quality models inevitably produce differing results. Scientific understanding of the complex atmospheric processes involved with PM formation and transport is increasing rapidly. The new $PM_{2.5}$ monitoring data now being collected nationwide, and improvements in the estimates of emissions from all sources, will help calibrate and verify the performance of air quality models. Existing air quality models are being improved constantly, and the next generation of PM air quality models are under development.

Particulate Matter Formation

Ambient concentrations of PM are composed of directly emitted particles and of secondary aerosols of sulfate, nitrate, and organics. Particulate matter is the generic term for the mixture of microscopic solid particles and liquid droplets found in the air. The particles are either emitted directly from these combustion sources or are formed in the atmosphere through reactions involving gases, such as SO_2 and NO_x.

REMSAD Air Quality Model

REMSAD was used to simulate estimates of particulate matter concentration for three future-year scenarios. Computer Sciences Corporation (CSC) performed the REMSAD modeling for both the EPA analysis and this report. Subsequently we used the modeling results to estimate the health-related costs for each of the scenarios in the primary analysis.

The REMSAD model is designed to simulate the effects of changes in emissions on PM concentrations and deposition. REMSAD calculates concentrations of pollutants by simulating the physical and chemical processes in the atmosphere. The basis for REMSAD is the atmospheric diffusion or species continuity equation. This equation represents a mass balance that includes all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes in mathematical terms.

Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, REMSAD can evaluate the air-quality effects of specific emission control scenarios. This is achieved by first replicating a historical ozone episode to establish a base-case simulation. CSC prepared model inputs from observed meteorological, emissions, and air quality data for selected episode days using various input preparation techniques. They apply the REMSAD model with these inputs, and the results are evaluated to determine model performance. Once the model results have been evaluated and determined to perform within prescribed levels, they combine the same base-case meteorological inputs with *modified* or *projected* emission inventories to simulate possible alternative/future emission scenarios.

The PM levels estimated by REMSAD were not directly used in EPA's health analysis of the Clear Skies Act, nor are the directly used here. Instead of using the REMSAD results directly, we use the REMSAD results to estimate the relative change in PM levels. We combine the REMSAD results with actual $PM_{2.5}$ monitor readings from 2001 to estimate the $PM_{2.5}$ levels actually used in the health analysis. This same procedure was used in the EPA Clear Skies Act health analysis. EPA believes this provides a better estimate of future $PM_{2.5}$ levels than the REMSAD modeling data itself.

At the location of each $PM_{2.5}$ monitor, we quantified the relationship between REMSAD estimated levels of $PM_{2.5}$ at the monitor for a base year (2001) and the future year (2010 or 2020). These REMSAD-based adjustment ratios are applied to the actual monitoring data to generate estimates of $PM_{2.5}$ levels at each monitor for each of the future scenarios.

In order to provide estimates of ambient $PM_{2.5}$ levels everywhere in the country, and not just at the monitors, an additional analytical step is required. To calculate population exposure to PM, each REMSAD grid cell was assigned a distance-weighted average of adjusted PM levels from a set of monitors that best surrounds the cell. This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (eVNA) spatial interpolation (See Abt Associates, 2000 for a more detailed description).

The estimated future baseline $PM_{2.5}$ levels estimated using the REMSAD and eVNA method, and the change in $PM_{2.5}$ levels associated with each policy option, are shown in the Exhibits 3.1 to 3.11. The maps depict annual mean $PM_{2.5}$ levels (in $\mu g/m^3$) Exhibits 3.1 and 3.2 show the future baseline $PM_{2.5}$ conditions in 2010 and 2020. Exhibits 3.3 through 3.7 show the estimated 2010 changes in the annual mean $PM_{2.5}$ level for the policy options and the No EGU scenario. Exhibits 3.8 through 3.11 show the estimated changes in 2020 for the policy options.

Exhibit 3.1 2010 Baseline Annual Mean $PM_{2.5}$ Levels

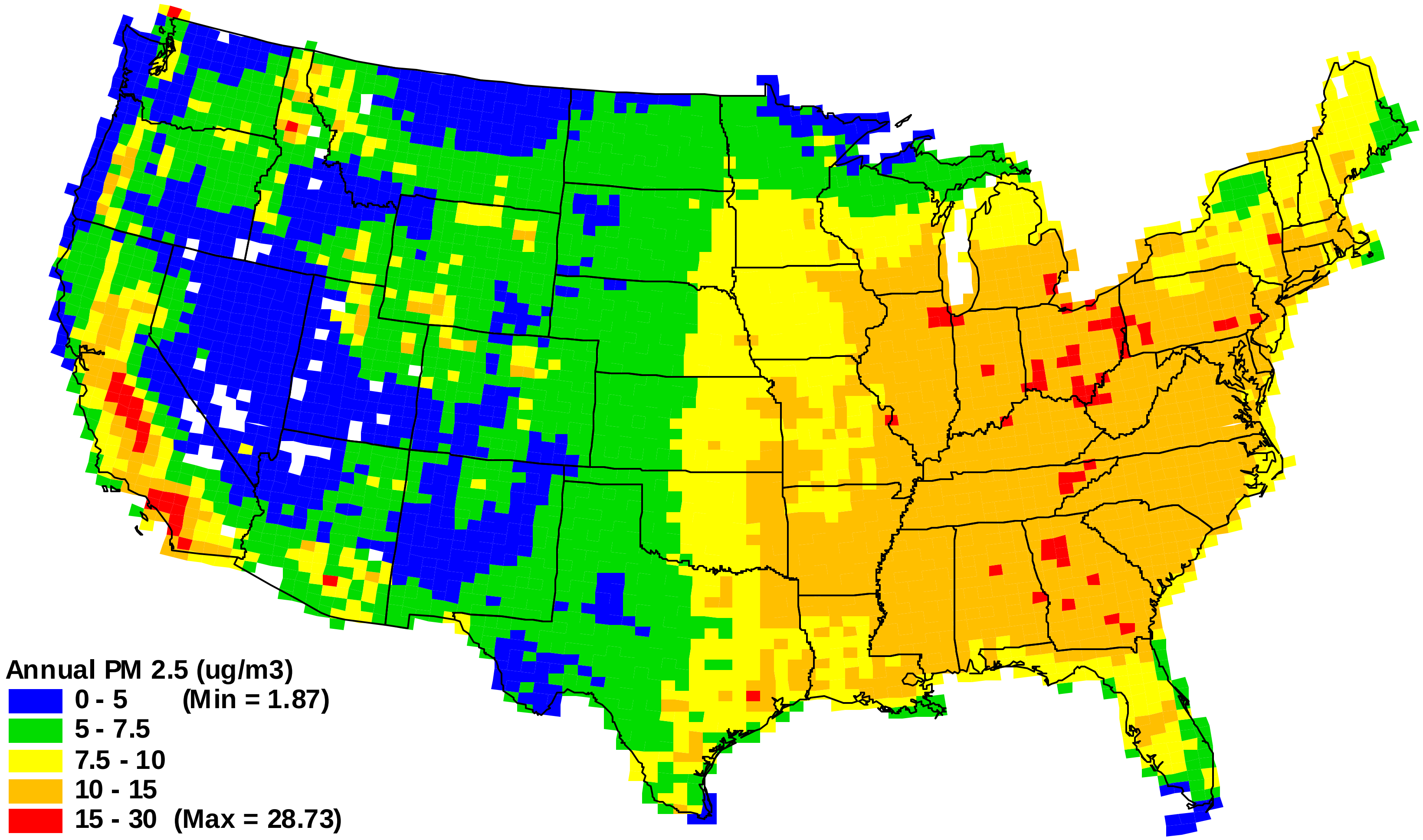


Exhibit 3.2 2020 Baseline Annual Mean $PM_{2.5}$ Levels

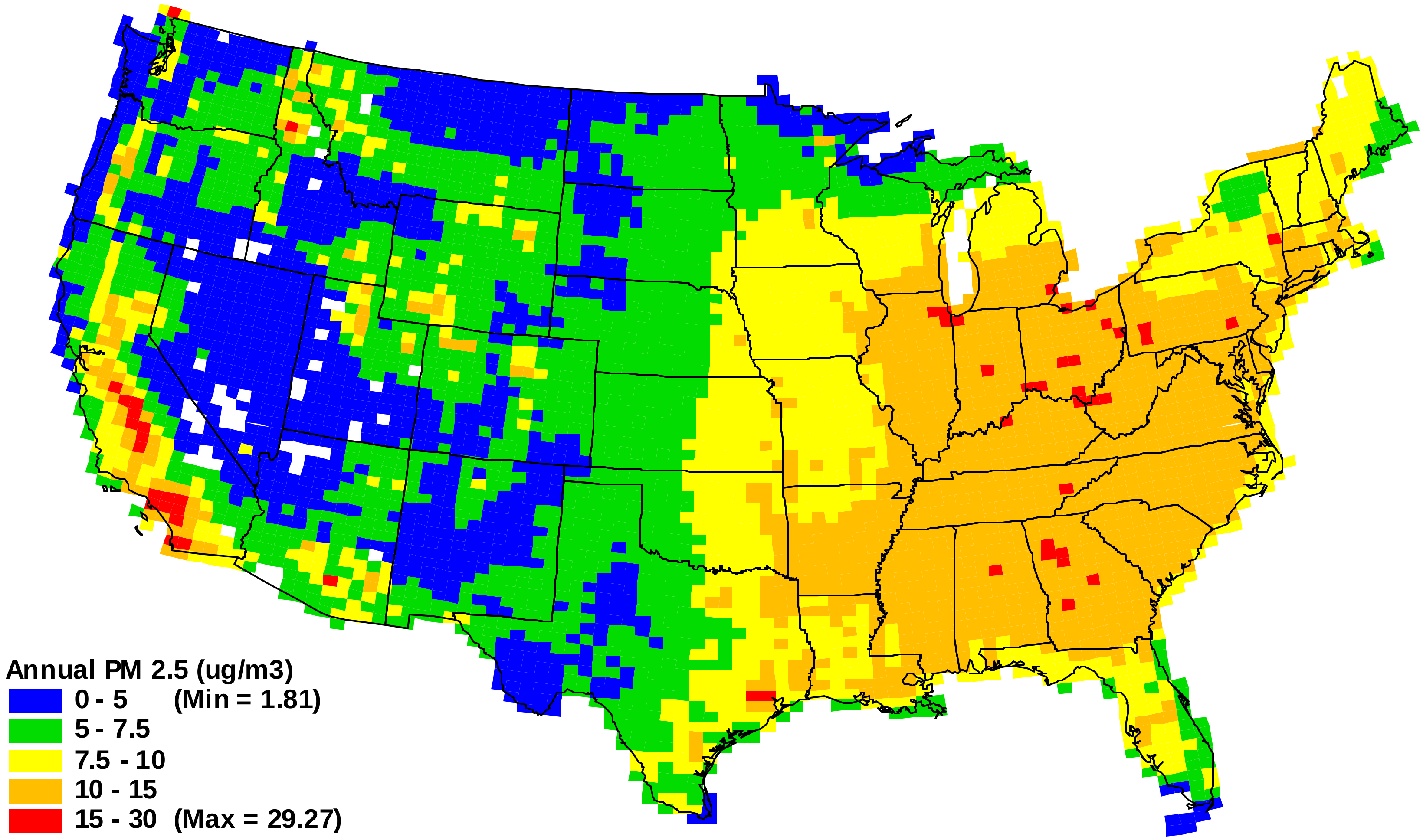


Exhibit 3.3 Change in 2010 Annual Mean $PM_{2.5}$ Levels with Clear Skies Act

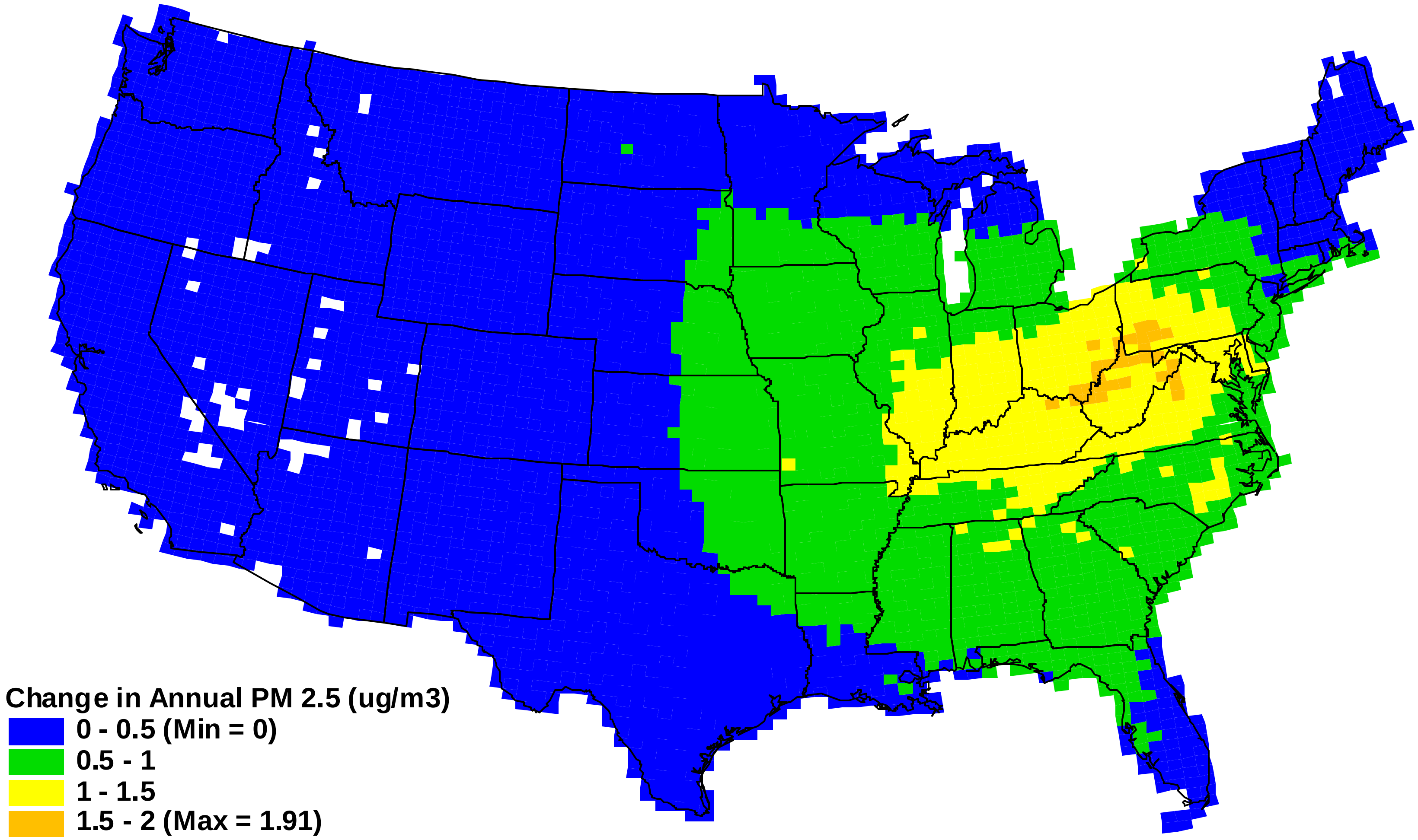


Exhibit 3.4 Change in 2010 Annual Mean $PM_{2.5}$ Levels with Carper Bill

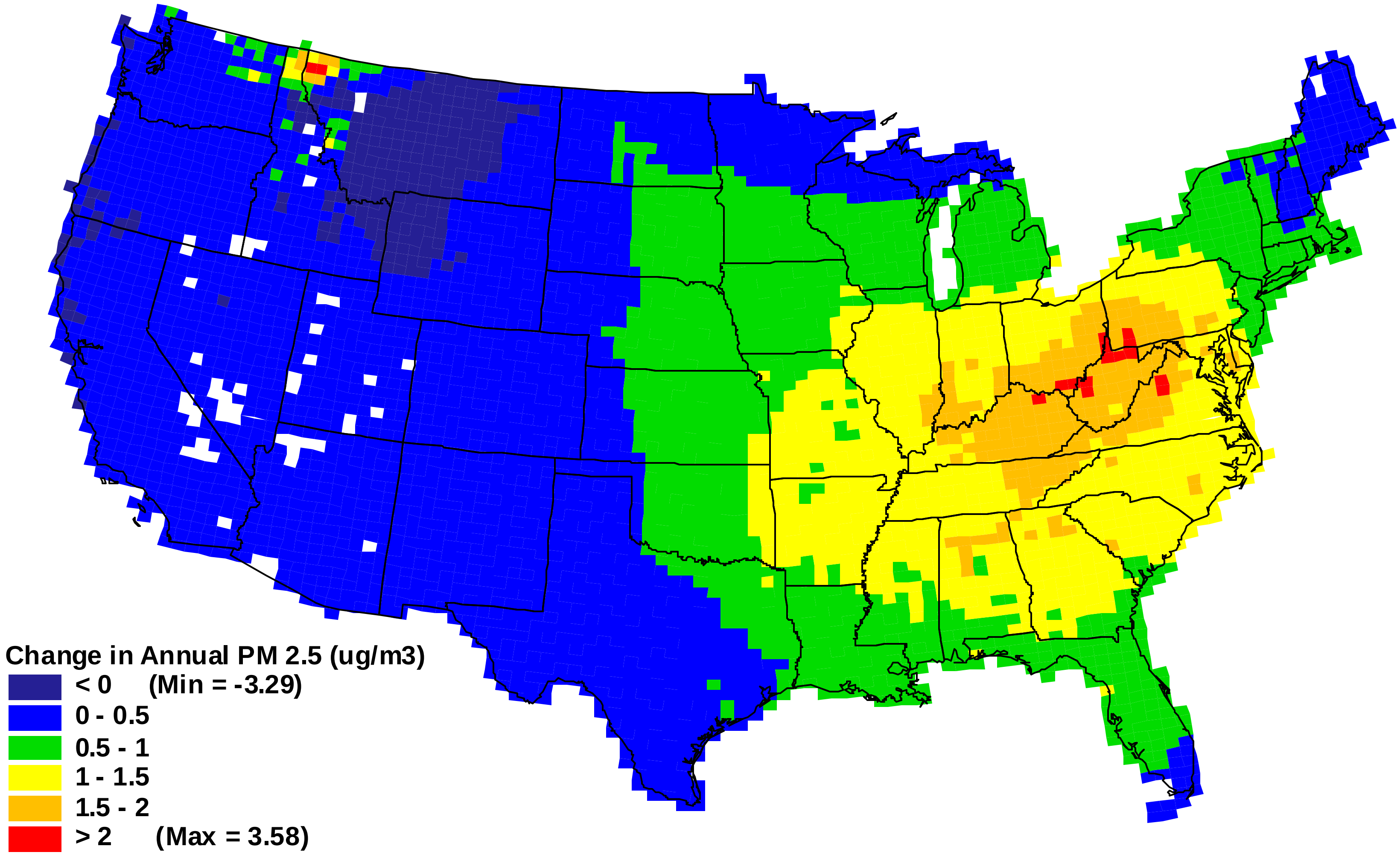


Exhibit 3.5 Change in 2010 Annual Mean $PM_{2.5}$ Levels with EPA Straw Proposal

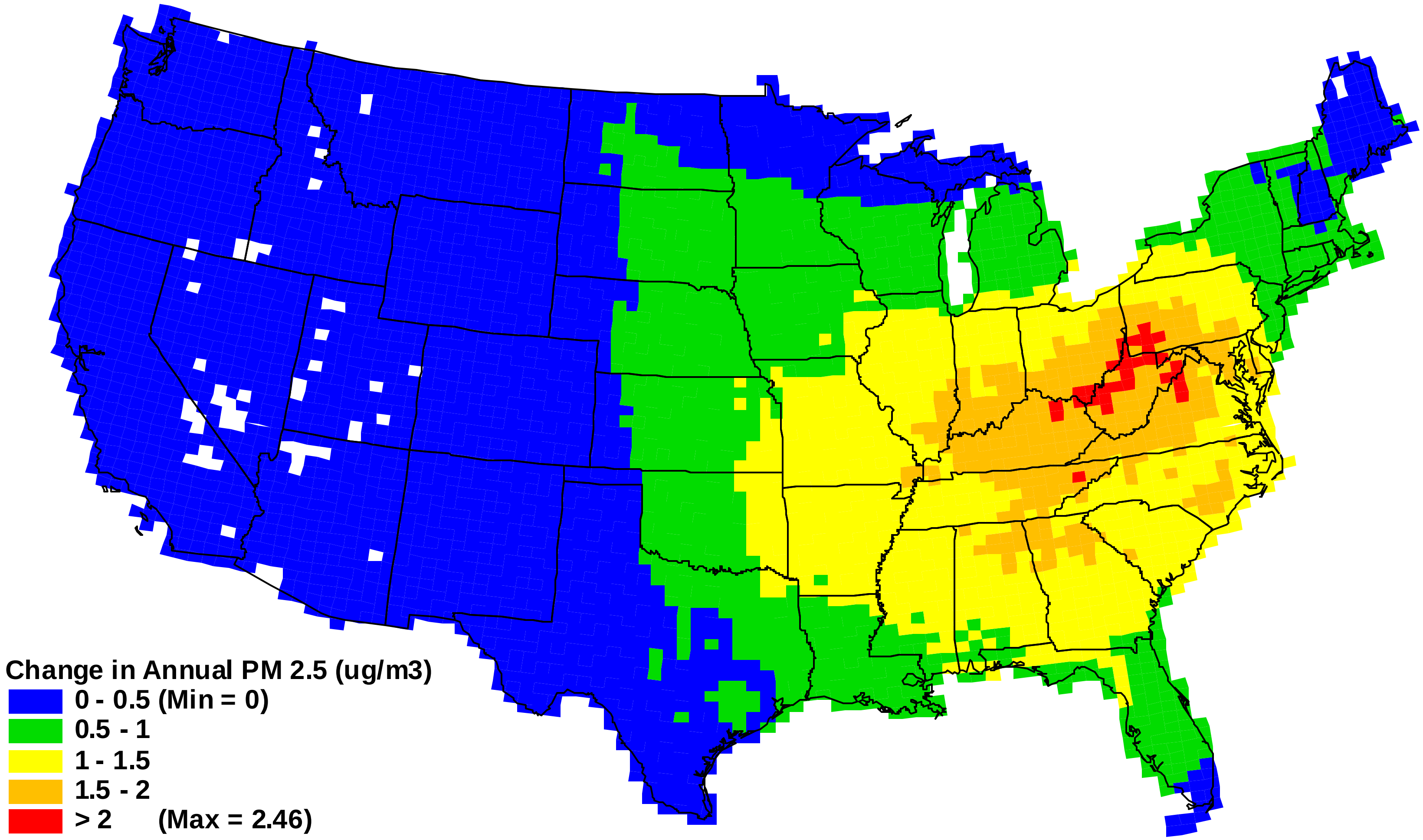


Exhibit 3.6 Change in 2010 Annual Mean $PM_{2.5}$ Levels with Jeffords Bill

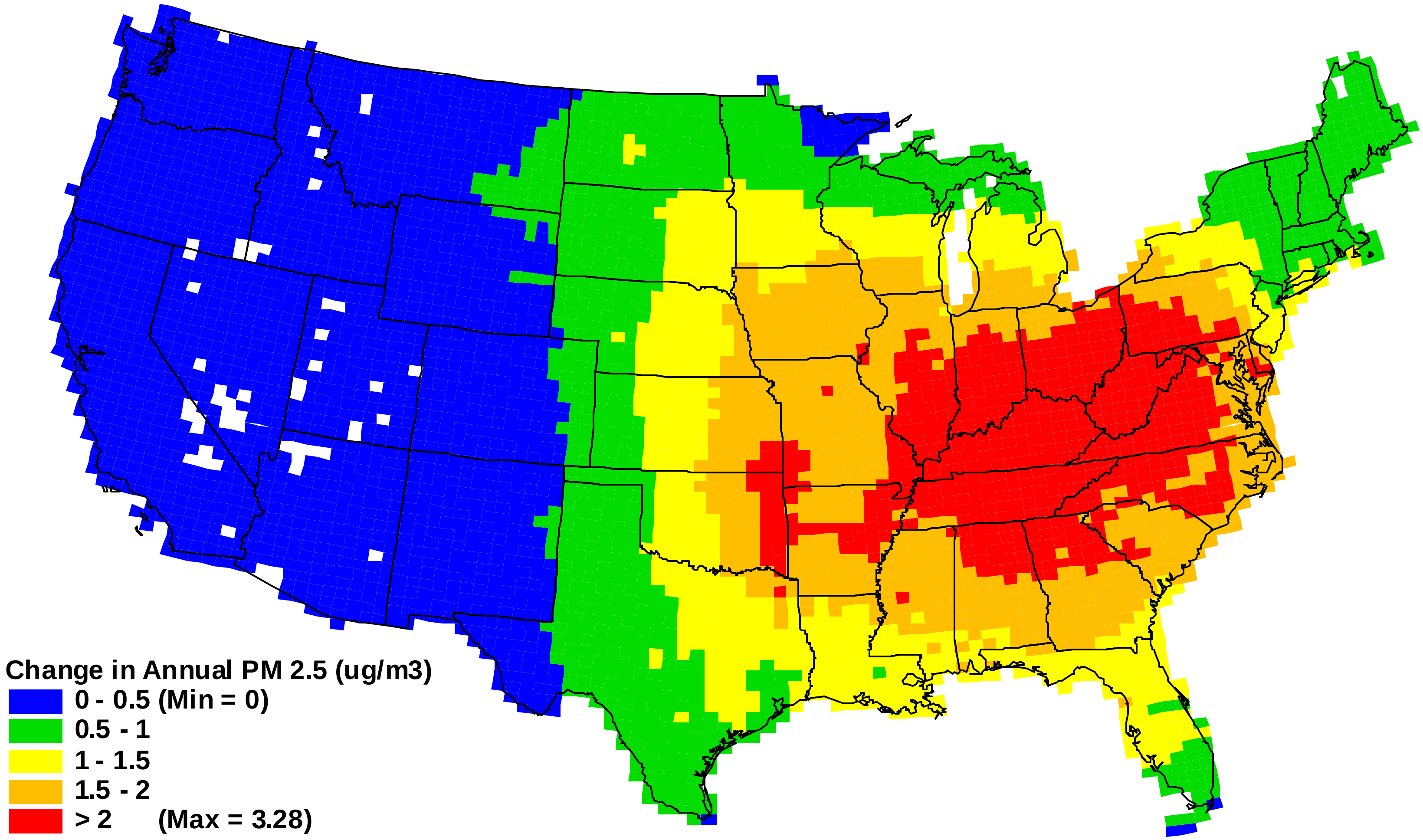


Exhibit 3.7 Change in 2010 Annual Mean $PM_{2.5}$ Levels for "No EGU" Scenario

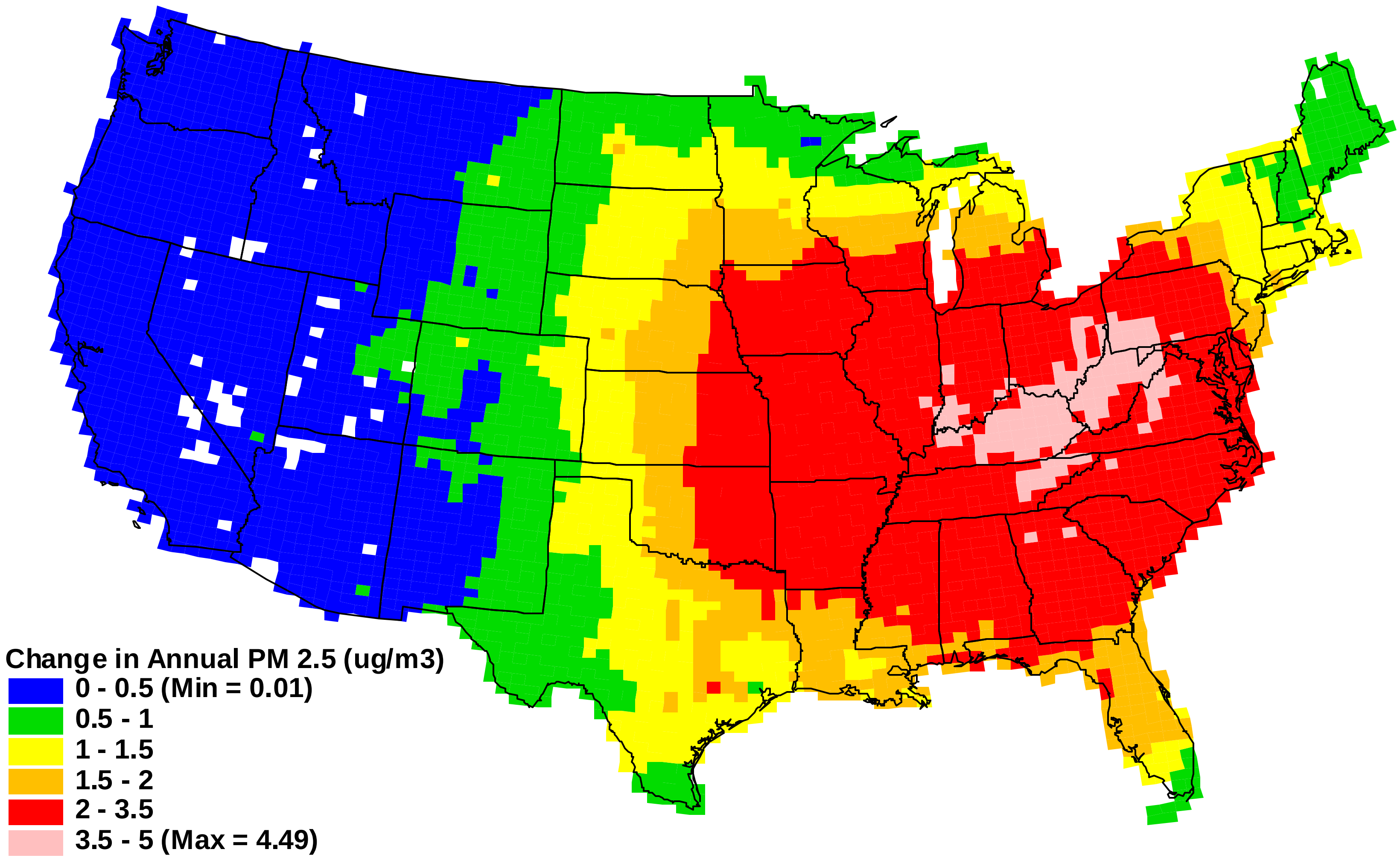


Exhibit 3.8 Change in 2020 Annual Mean $PM_{2.5}$ Levels with Clear Skies Act

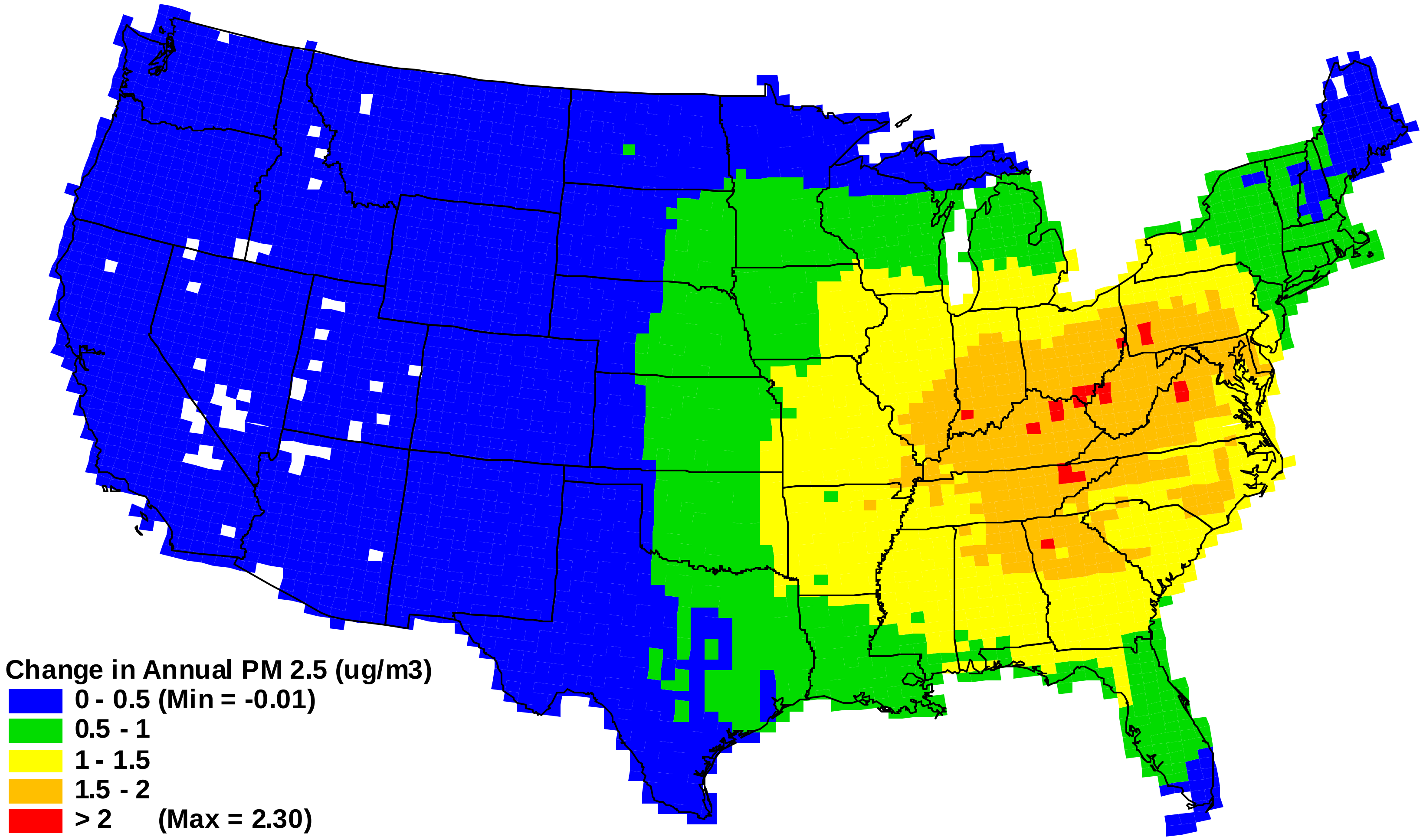


Exhibit 3.9 Change in 2020 Annual Mean $PM_{2.5}$ Levels with EPA Straw Proposal

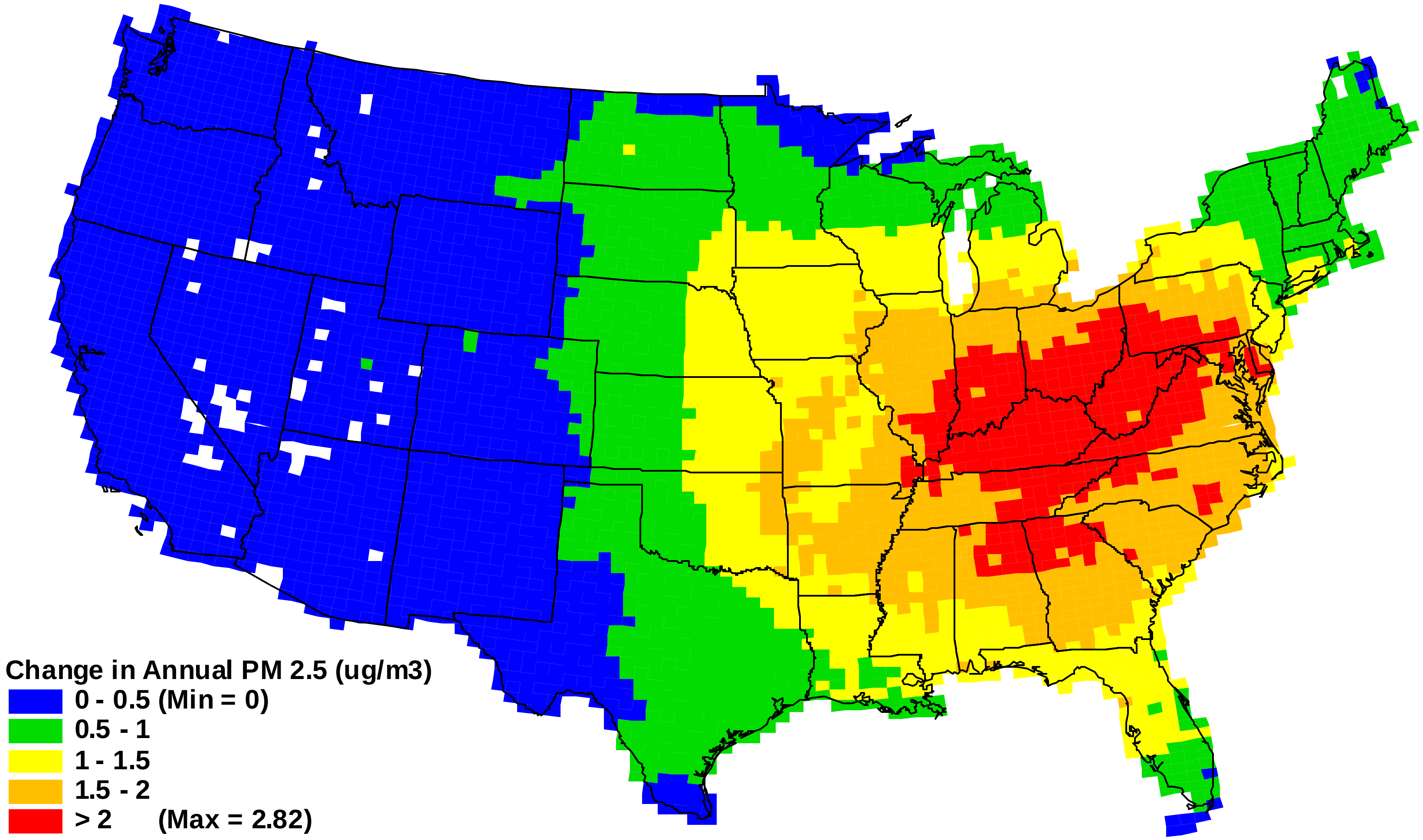


Exhibit 3.10 Change in 2020 Annual Mean $PM_{2.5}$ Levels with Carper Bill

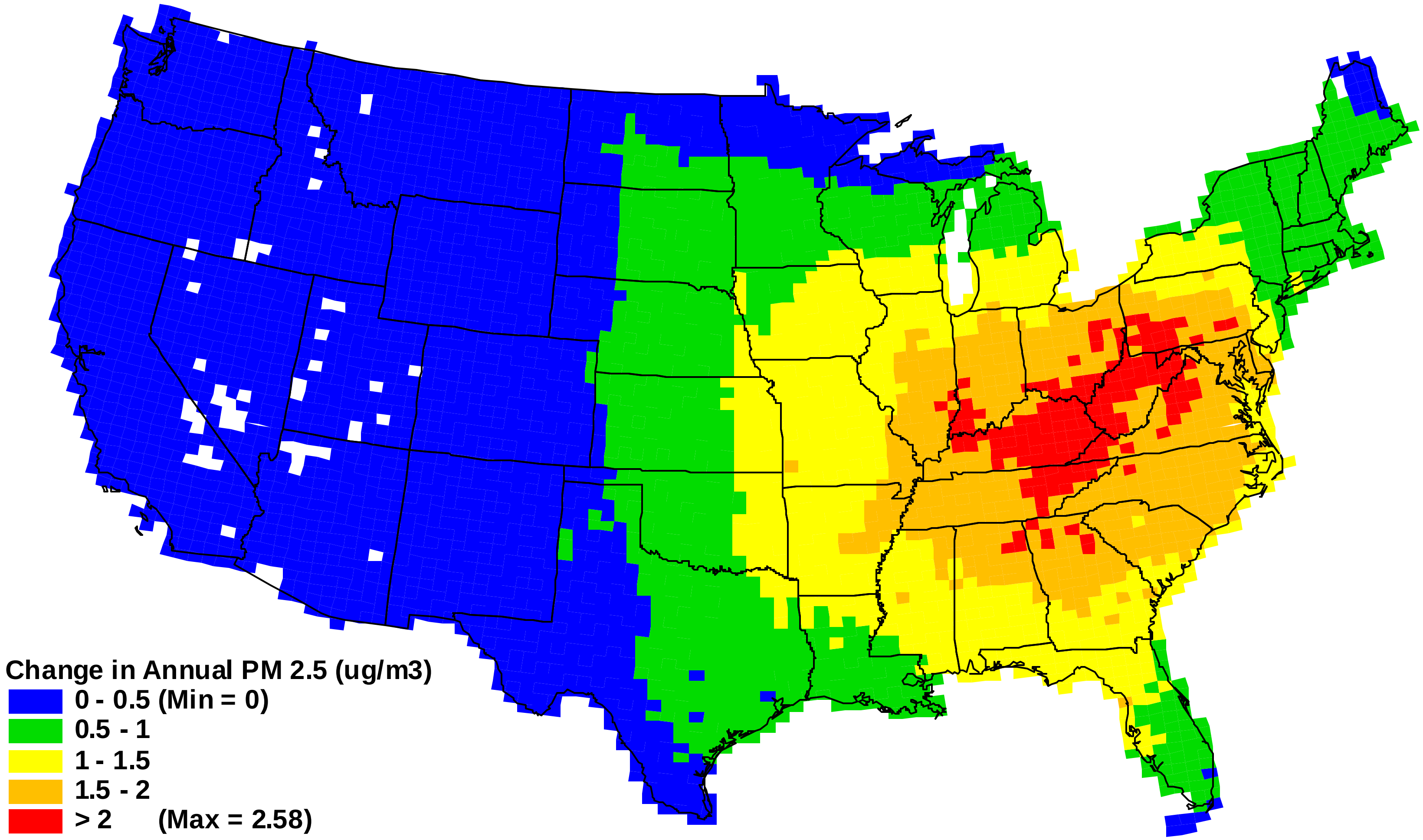
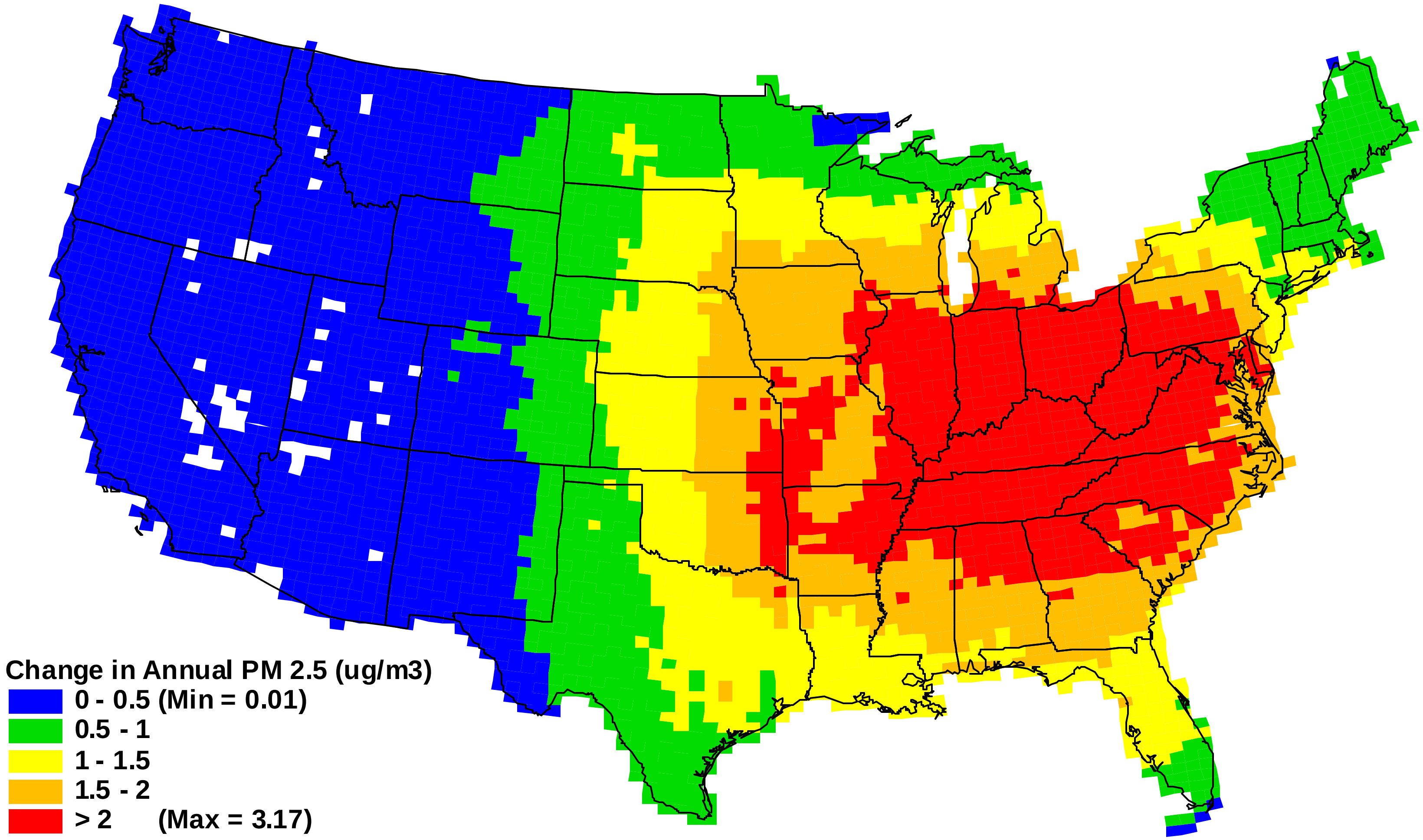


Exhibit 3.11 Change in 2020 Annual Mean $PM_{2.5}$ Levels with Jeffords Bill



4 Issues in Estimating Health Benefits

Changes in PM levels result in changes in a number of health effects, or “endpoints,” that society values. This chapter discusses key issues in the estimation of adverse health effects and in the valuation of health benefits. Section 1 describes general issues that particularly affect the estimation of changes in health effects. Section 2 describes general issues in valuing health changes. Finally, Section 3 discusses how uncertainty is characterized in this analysis.

Estimating Adverse Health Effects

This section reviews issues that arise in the estimation of adverse health effects. It reviews the derivation of C-R functions, and it reviews how BenMAP combines air quality data and C-R functions. In addition, we discuss how we handle overlapping health effects, thresholds, estimating the baseline incidence rates for the C-R functions, and other issues.

Basic Concentration-Response Model

While several health endpoints have been associated with exposure to ambient PM, the discussion below refers only to a generic “health endpoint,” denoted as y. The discussion refers to estimation of changes in the incidence of the health endpoint at a single location (the population cell, which is equivalent to the REMSAD gridcell). Region-wide changes are estimated by summing the estimated changes over all population cells in the region.

Different epidemiological studies may have estimated the relationship between PM and a particular health endpoint in different locations. The C-R functions estimated by these different studies may differ from each other in several ways. They may have different functional forms; they may have measured PM concentrations in different ways; they may have characterized the health endpoint, y, in slightly different ways; or they may have considered different types of populations. For example, some studies of the relationship between ambient PM concentrations and mortality have excluded accidental deaths from their mortality counts; others have included all deaths. One study may have measured daily (24-hour) average PM concentrations while another study may have used two-day averages. Some studies have assumed that the relationship between y and PM is best described by a linear form (i.e., the relationship between y and PM is estimated by a linear regression in which y is the dependent variable and PM is one of several independent variables). Other studies have assumed that the relationship is best described by a log-linear form (i.e., the relationship between the natural logarithm of y and PM is estimated by a linear regression).[1] Finally, one study may have considered changes in the health endpoint only among members of a particular subgroup of the population (e.g., individuals 65 and older), while other studies may have considered the entire population in the study location.

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[1]The log-linear form used in the epidemiological literature on PM-related health effects is often referred to as “Poisson regression” because the underlying dependent variable is a count (e.g., number of deaths), assumed to be Poisson distributed. The model may be estimated by regression techniques but is often estimated by maximum likelihood techniques. The form of the model, however, is still log-linear.

The estimated relationship between PM and a health endpoint in a study location is specific to the type of population studied, the measure of PM used, and the characterization of the health endpoint considered. For example, a study may have estimated the relationship between daily average PM concentrations and daily hospital admissions for "respiratory illness," among individuals age 65 and older, where "respiratory illness" includes International Classification of Disease (ICD) codes A, B, and C.[2] If any of the inputs had been different (for example, if the entire population had been considered, or if "respiratory illness" had consisted of a different set of ICD codes), the estimated C-R function would have been different. When using a C-R function estimated in an epidemiological study to estimate changes in the incidence of a health endpoint corresponding to a particular change in PM in a population cell, then, it is important that the inputs be appropriate for the C-R function being used -- i.e., that the measure of PM, the type of population, and the characterization of the health endpoint be the same as (or as close as possible to) those used in the study that estimated the C-R function.

Estimating the relationship between PM and a health endpoint, y, consists of (1) choosing a functional form of the relationship and (2) estimating the values of the parameters in the function assumed. The two most common functional forms in the epidemiological literature on PM and health effects are the log-linear and the linear relationship. The log-linear relationship is of the form:

$$y = Be^{b \cdot PM} \quad ,$$

or, equivalently,

$$\ln(y) = a + b \cdot PM \quad ,$$

where the parameter B is the incidence of y when the concentration of PM is zero, the parameter β is the coefficient of PM, ln(y) is the natural logarithm of y, and α = ln(B).[3] If the functional form of the C-R relationship is log-linear, the relationship between ΔPM and Δy is:

$$\Delta y = y \cdot \left(e^{b \cdot \Delta PM} - 1\right) ,$$

where y is the baseline incidence of the health effect (i.e., the incidence before the change in PM). For a log-linear C-R function, the relative risk (RR) associated with the change ΔPM is:

$$RR_{\Delta PM} = e^{b \cdot \Delta PM} \quad .$$

---

[2] The International Classification Codes are described at the website of the Medical Center Information Systems: Duke University Health Systems (1999).

[3] Other covariates besides pollution clearly affect mortality. The parameter B might be thought of as containing these other covariates, for example, evaluated at their means. That is, $B = B_o \exp\{\beta_1 x_1 + \ldots + \beta_n x_n\}$, where B_o is the incidence of y when all covariates in the model are zero, and $x_1, \ldots , x_n$ are the other covariates evaluated at their mean values. The parameter B drops out of the model, however, when changes in incidences are calculated, and is therefore not important.

Epidemiological studies often report a relative risk for a given ΔPM, rather than the coefficient, β, in the C-R function. The coefficient can be derived from the reported relative risk and ΔPM, however, by solving for β:

$$b = \frac{\ln(RR)}{\Delta PM} \ .$$

The linear relationship is of the form:

$$y = a + b \cdot PM \ ,$$

where α incorporates all the other independent variables in the regression (evaluated at their mean values, for example) times their respective coefficients. When the C-R function is linear, the relationship between a relative risk and the coefficient, β, is not quite as straightforward as it is when the function is log-linear. Studies using linear functions usually report the coefficient directly.

If the functional form of the C-R relationship is linear, the relationship between ΔPM and Δy is simply:

$$\Delta y = b \cdot \Delta PM \ .$$

A few epidemiological studies, estimating the relationship between certain morbidity endpoints and PM, have used functional forms other than linear or log-linear forms. Of these, logistic regressions are the most common. Abt Associates (1999, Appendix A) provides further details on the derivation of dose-response functions.

Calculation of Adverse Health Effects with BenMAP

The health effects analysis in this report was prepared using BenMAP, which is being developed by Abt Associates Inc. for the US EPA. Although BenMAP is still being revised and expanded, the same version of BenMAP was used in this analysis as was used for EPA's analysis in 2003 of the Clear Skies Act. BenMAP is a population-based system for modeling exposure to ambient levels of criteria air pollutants and estimating the adverse health effects associated with this exposure. BenMAP uses the same grid cell configuration as REMSAD ver 7.06 (36km x 36km), and estimates the changes in incidence of adverse health effects associated with given changes in air quality in each grid cell. The national incidence change (or the changes within individual states or counties) is then calculated as the sum of grid-cell-specific changes.

To reflect the uncertainty surrounding predicted incidence changes resulting from the uncertainty surrounding the pollutant coefficients in the C-R functions used, BenMAP produces a *distribution* of possible incidence changes for each adverse health, rather than a single point estimate. To do this, it uses both the point estimate of the pollutant coefficient (β in the above equation) and the standard error of the estimate to produce a normal distribution with mean equal to the estimate of β and standard deviation equal to the standard error of the estimate. Using a Latin Hypercube method,[4] we take the n^{th} percentile value of β from this normal distribution, for n = 0.5, 1.5, ..., 99.5, and follow the procedure outlined in the section above to produce an estimate of the incidence change, given the β selected. Repeating the procedure for each value of β selected results in a distribution of incidence changes in the BenMAP grid cell. This distribution is stored, and BenMAP proceeds to the next grid cell, where the process is repeated. We calculate the distribution of the national change (or change in a designated geographical area) by summing the n^{th} percentile grid cell-specific changes, for n = 0.5, 1.5, ..., 99.5.

Overlapping Health Effects

Several endpoints reported in the health effects literature overlap with each other. For example, hospital admissions for single respiratory ailments (e.g. pneumonia) overlap with estimates of hospital admissions for "all respiratory" ailments.[5] Similarly, several studies quantify the occurrence of respiratory symptoms where the definitions of symptoms are not unique (e.g., shortness of breath or upper respiratory symptoms). In choosing studies to include in the aggregated benefits estimate (discussed below), this analysis carefully considers the issue of double-counting benefits that might arise from overlapping health effects.

Baseline Incidences

As noted above, most of the relevant C-R functions are log-linear, and the estimation of incidence changes based on a log-linear C-R function requires a baseline incidence. The baseline incidence for a given REMSAD/BenMAP population cell is the baseline incidence rate in that location multiplied by the relevant population. County mortality rates are used in the estimation of air pollution-related mortality, and all BenMAP population cells in the county are assumed to have the same mortality rate. Hospital admissions are only available at the national level, so all areas are assumed to have the same incidence rate for a given population age group. For some endpoints, such as respiratory symptoms and illnesses and restricted activity days, baseline incidence rates are not available even at the national level. The only sources of estimates of baseline incidence rates in such cases are the studies reporting the C-R functions for those health endpoints. The baseline incidence rate and its source are given for each C-R function in Appendix A.

Thresholds

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[4]The Latin Hypercube method is used to enhance computer processing efficiency. It is a sampling method that divides a probability distribution into intervals of equal probability, with an assumption value for each interval assigned according to the interval's probability distribution. Compared with conventional Monte Carlo sampling, the Latin Hypercube approach is more precise over a fewer number of trials because the distribution is sampled in a more even, consistent manner (Decisioneering, 1996, pp. 104-105).

[5]Pneumonia is often classified with the International Classification of Diseases (ICD) codes of 480-486, while all respiratory admissions are classified with ICD codes 460-519.

A very important issue in applied modeling of changes in PM is whether to apply the C-R functions to all predicted changes in ambient concentrations, even small changes occurring at levels approaching the concentration in which they exist in the natural environment (without interference from humans), referred to as "anthropogenic background." Different assumptions about whether to model thresholds, and if so, at what levels, can have a major effect on the resulting benefits estimates.

None of the epidemiological functions relating PM to various health endpoints incorporate thresholds. Instead, all of these functions are continuous and differentiable down to zero pollutant levels. A threshold may be imposed on these models, however, in several ways, and there are various points at which the threshold could be set. (A threshold can be set at any point. There are some points, however, that may be considered more obvious candidates than others.) One possible threshold might be the background level of the pollutant. Another might be a relevant standard for the pollutant. Whatever the threshold, the implication is that there are no effects below the threshold.

A threshold model can be constructed in more than one way. One method is to simply truncate the C-R function at the threshold (i.e., to not include any physical effect changes associated with PM concentrations below the designated threshold). This method uses the original C-R function, but calculates the change in PM as [max(T,baseline PM) - max(T, regulatory alternative PM)], where T denotes the designated threshold. This threshold model will predict a smaller incidence of the health effect than the original model without a threshold. Clearly, as T increases, the predicted incidence of the health effect will decrease.

An alternative method is to replace the original C-R function with a "hockey stick" model that best approximates the original function estimated using actual data. The hockey stick model is horizontal up to a designated threshold PM level, T, and is linear with a positive slope for PM concentrations greater than T. Recall the log-linear C-R function:

$$y = a + b \cdot PM \ .$$

Assuming that the value of the coefficient, β, depends on the level of PM, we get:

$$\begin{aligned} \ln(y) &= a' \ , \quad for\ PM \leq T \ , and \\ \ln(y) &= a' + b' \cdot PM \ , \quad for\ PM > T \ . \end{aligned}$$

Ideally, the coefficients would be estimated based on the data in the original study – that is, a hockey stick model would be fit to the original data, so that the threshold model that is most consistent with the available information would be chosen. If a threshold model could be estimated from the original data, it is unlikely that α' would equal α or that β' would equal β, because such a hockey stick model would be consistently below the original model (equation (6)), except at PM=0 (where the two models would coincide). If that were the hockey stick model that best fit the data, then it is unlikely that the best fitting linear model would be consistently above it. Instead, the hockey stick model that best fits the same data would most likely have α'>α and β'>β. A graph of this model would therefore cross the graph of the linear model at two points. Whether such a hockey stick threshold model predicted a greater or smaller incidence of the health effect than the linear model would depend on the distribution of PM levels. It is worth noting that the graph of the first type of threshold model, in which the C-R function is simply truncated at the threshold, would be discontinuous at the threshold. This is highly unlikely to be a good model of the actual relationship between PM and any health endpoint.

There is some evidence that, at least for particulate matter, not only is there no threshold, but the PM coefficient may actually be larger at lower levels of PM and smaller at higher levels. Examining the relationship between particulate matter (measured as TSP) and mortality in Milan, Italy during the ten year period 1980-1989, Rossi et al. (1999) fitted a model with one slope across the entire range of TSP and an additional slope for TSP greater than 200 $\mu g/m^3$. The second slope was statistically significant ($p<0.0001$) and negative, indicating a lower slope at higher TSP levels.

Application of a Single C-R Function Everywhere

Whether the C-R relationship between a pollutant and a given health endpoint is estimated by a single function from a single study or by a pooled function of C-R functions from several studies, that same C-R relationship is applied everywhere in the benefits analysis. Although the C-R relationship may in fact vary somewhat from one location to another (for example, due to differences in population susceptibilities or differences in the composition of PM), location-specific C-R functions are available only for those locations in which studies were conducted. While a single function applied everywhere may result in overestimates of incidence changes in some locations and underestimates of incidence changes in other locations, these location-specific biases will to some extent cancel each other out when the total incidence change is calculated. It is not possible to know the extent or direction of the bias in the total incidence change based on application of a single C-R function everywhere.

Estimating Pollutant-Specific Benefits Using Single Pollutant vs. Multi-Pollutant Models

Many studies include multiple pollutants, like ozone and particulate matter, in their final models. For this analysis, however, we are estimating benefits for only particulate matter. This presents a challenge because it is often difficult to separate out the effect of a single pollutant from the effects of other pollutants in the mix. Multi-pollutant models have the advantage that the coefficient for a single pollutant in such a model will be unbiased (so that the effects of other pollutants will not be attributed falsely to the single pollutant). However, the variance of the estimator of the coefficient of the pollutant of interest will increase as the correlations between the other pollutants in the model and that pollutant increase. If the other pollutants in the model are highly correlated with the pollutant of interest, we would have an unbiased but unstable (high variance) estimator. However, while single pollutant models have the advantage of more stable estimators, the coefficient estimate in a single pollutant model could be biased in such a model. We could consider the single pollutant as an "indicator pollutant" – i.e., an indicator of a pollution mix – if we use single pollutant models. However, there is no guarantee that the composition of the pollution mix will remain the same under a control scenario that targets only a single pollutant.

This analysis uses both single pollutant and multi-pollutant models to derive PM-specific benefit estimates. When more than one study has estimated the relationship between a given endpoint and a given pollutant, information from both single-pollutant and multi-pollutant models may be pooled to derive pollutant-specific benefits estimates. For example, the benefits predicted by a model with only PM may be pooled with the benefits predicted by a model with both PM and ozone to derive an estimate of the PM-related benefits associated with a given endpoint.

Though this analysis estimates the benefits associated with reductions in PM alone, it is worth mentioning that there is the possibility of mis-characterizing benefits if some of the studies used are single pollutant models. Suppose, for example, that only ozone is actually associated with a given endpoint, but PM appears to be associated only because it is correlated with ozone. The benefits predicted by a single pollutant PM model would, in that case, actually reflect the benefits of reducing ozone, to the extent that PM and ozone are correlated. If only one pollutant is being associated with the endpoint in this analysis (e.g., chronic bronchitis is associated only with PM in this analysis), this is not a problem.

Pooling Study Results

When only a single study estimated the C-R relationship between a pollutant and a given health endpoint, the estimation of a population cell-specific incidence change, Δy, is straightforward, as noted above. When several studies have estimated C-R relationships between a pollutant and a given health endpoint, the results of the studies can be pooled to derive a single estimate of the function. If the functional forms, pollutant averaging times, and study populations are all the same (or very similar), a pooled, "central tendency" C-R function can be derived from multiple study-specific C-R functions. Even if there are differences among the studies, however, that make a pooled C-R function infeasible, a pooled estimate of the incidence change, Δy, and/or the monetary benefit of the incidence change can be obtained by incorporating the appropriate air quality data into the study-specific C-R functions and pooling the resulting study-specific predictions of incidence change. Similarly, study-specific predictions of incidence change can be combined with unit dollar values to produce study-specific predictions of benefits.

Whether the pooling is done in "coefficient space," "incidence change space," or "dollar space," the question of the relative weights assigned to the estimates (of coefficients, incidence changes, or dollar benefits) from each input study must be addressed. One possibility is simply averaging the estimates from all the studies. This has the advantage of simplicity, but the disadvantage of not taking into account the measured uncertainty of each of the estimates. Estimates with great uncertainty surrounding them are given the same weight as estimates with very little uncertainty.

An alternative approach to pooling incidence estimates from different studies is to give more weight to studies with little estimated variance than to studies with a great deal of estimated variance. The exact way in which weights are assigned to estimates from different studies in a pooled analysis depends on the underlying assumption about how the different estimates are related to each other. Under the assumption that there is actually a distribution of true effect coefficients, or β's, that differ by location and/or study (referred to as the random effects model), the different coefficients reported by different studies may be estimates of *different* underlying coefficients, rather than just different estimates of the same coefficient. In contrast to the "fixed-effects" model (which assumes that there is only one β everywhere), the random-effects model allows the possibility that different studies are estimating different parameters.[6]

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[6] In studies of the effects of PM_{10} on mortality, for example, if the composition of PM_{10} varies among study locations the underlying relationship between mortality and PM_{10} may be different from one study location to another. For example, fine particles make up a greater fraction of PM_{10} in Philadelphia County than in Southeast Los Angeles County. If fine particles are disproportionately responsible for mortality relative to coarse particles, then one would expect the true value of β for PM_{10} in Philadelphia County to be greater than the true value of β for PM_{10} in Southeast Los Angeles County. This would

A third approach to pooling studies is to apply subjective weights to the studies, rather than conducting a random effects pooling analysis. If the analyst is aware of specific strengths and weaknesses of the studies involved, this prior information may be used as input to the calculation of weights which reflect the relative reliability of the estimates from the studies.

In those cases in which pooling of information from multiple studies was an option in this analysis, pooling was done in both “incidence change space” and “dollar benefit space.” The hypothesis of fixed effects was tested. If this hypothesis was rejected, an underlying random effects model was used as the basis for weighting of studies. A more detailed description of the pooling procedure used is given below in the section on hospital admissions.

Valuing Changes in Health Effects

This section discusses a number of issues that arise in valuing changes in health effects. The first section provides some background on willingness to pay (WTP). The second section discusses the possibility that as income changes then WTP would also change. The third section describes inflation issues are addressed. The WTP estimates were originally calculated in a variety of different years, and hence reflect values in values expressed in the a variety of different inflation amounts. The fourth section describes how we adjust the original WTP estimates dollars to correct for inflation to get estimates in 1999 dollars. In the last section, we briefly review how we aggregate benefits estimates.

Willingness To Pay Estimation

WTP is a measure of value an individual places on gaining an outcome viewed as desirable, be it something that can be purchased in a market or not. The WTP measure, therefore, is the amount of money such that the individual would be indifferent between having the good (or service) and having the money. An alternative measure of economic value is willingness to accept (WTA) a monetary compensation to offset a deterioration in welfare, such that the individual would be indifferent between having the money and not having the deterioration. Whether WTP or WTA is the appropriate measure depends on how property rights are assigned. Consider an increase in air pollution. If society has assigned property rights so that people have a right to clean air, then they must be compensated for an increase in the level of air pollution. The appropriate measure of the value of avoiding an increase in air pollution, in this case, would be the amount people would be willing to accept in compensation for the more polluted air. If, on the other hand, society has not assigned people the right to clean air, then the appropriate measure of the value of avoiding an increase in air pollution would be what people are willing to pay to avoid it. The assignment of property rights in our society is unclear. WTP is by far the more common measure used in benefits analyses, however, reflecting the fact that this is a much more common measure in the empirical valuation literature. In this analysis, wherever possible, the valuation measures are in terms of WTP. Where such estimates are not available, alternative measures are used, such as cost-of-illness and wage-risk studies. These are discussed for each endpoint where applicable.

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violate the assumption of the “fixed effects” model. However, applying a random effects model assumes that the observed set of coefficients is representative of coefficients in the policy region.

For both market and non-market goods, WTP reflects individuals' preferences. Because preferences are likely to vary from one individual to another, WTP for both market (e.g., the purchase of a new automobile) and non-market goods (e.g., health-related improvements in environmental quality) is likely to vary from one individual to another. In contrast to market goods, non-market goods such as environmental quality improvements, are public goods, whose benefits are shared by many individuals. The individuals who benefit from the environmental quality improvement may have different WTPs for this non-market good. The total social value of the good is the sum of the WTPs of all individuals who "consume" (i.e., benefit from) the good.

In the case of health improvements related to pollution reduction, it is not certain specifically who will receive particular benefits of reduced pollution. For example, the analysis may predict 100 hospital admissions for respiratory illnesses avoided, but the analysis does not estimate which individuals will be spared those cases of respiratory illness that would have required hospitalization. The health benefits conferred on individuals by a reduction in pollution concentrations are, then, actually *reductions in the risk* of having to endure certain health problems. These benefits (reductions in risk) may not be the same for all individuals (and could be zero for some individuals). Likewise, the WTP for a given benefit is likely to vary from one individual to another. In theory, the total social value associated with the decrease in risk of a given health problem resulting from a given reduction in pollution concentrations is:

$$\sum_{i=1}^{N} WTP_i\left(B_i\right) ,$$

where B_i is the benefit (i.e., the reduction in risk of having to endure the health problem) conferred on the i^{th} individual (out of a total of N) by the reduction in pollution concentrations, and $WTP_i(B_i)$ is the i^{th} individual's WTP for that benefit.

If a reduction in pollution concentrations affects the risks of several health endpoints, the total health-related social value of the reduction in pollution concentrations is:

$$\sum_{i=1}^{N} \sum_{j=1}^{J} WTP_i\left(B_{i,j}\right) ,$$

where B_{ij} is the benefit related to the j^{th} health endpoint (i.e., the reduction in risk of having to endure the j^{th} health problem) conferred on the i^{th} individual by the reduction in pollution concentrations, and $WTP_i(B_{ij})$ is the i^{th} individual's WTP for that benefit.

The reduction in risk of each health problem for each individual is not known, nor is each individual's WTP for each possible benefit he or she might receive known. Therefore, in practice, benefits analysis estimates the value of a *statistical* health problem avoided. For example, although a reduction in pollutant concentrations may save actual lives (i.e., avoid premature mortality), whose lives will be saved cannot be known *ex ante*. What is known is that the reduction in air pollutant concentrations results in a reduction in mortality risk. It is this reduction in mortality risk that is valued in a monetized benefit analysis. Individual WTPs for small reductions in mortality risk are summed over enough individuals to infer the value of a *statistical* life saved. This is different from the value of a particular, identified life saved. Rather than "WTP to avoid a death," then, it is more accurate to use the term "the value of a statistical life."

Suppose, for example, that a given reduction in PM concentrations results in a decrease in mortality risk of 1/10,000. Then for every 10,000 individuals, one individual would be expected to die in the absence of the reduction in PM concentrations (who would not die in the presence of the reduction in PM concentrations). If WTP for this 1/10,000 decrease in mortality risk is $500 (assuming, for now, that all individuals' WTPs are the same), then the value of a statistical life is 10,000 x $500, or $5 million.

A given reduction in PM concentrations is unlikely, however, to confer the same risk reduction (e.g., mortality risk reduction) on all exposed individuals in the population. (In terms of the expressions above, B_i is not necessarily equal to B_j, for $i \neq j$). In addition, different individuals may not be willing to pay the same amount for the same risk reduction. The above expression for the total social value associated with the decrease in risk of a given health problem resulting from a given reduction in pollution concentrations may be rewritten to more accurately convey this. Using mortality risk as an example, for a given unit risk reduction (e.g., 1/1,000,000), the total mortality-related benefit of a given pollution reduction can be written as:

$$\sum_{i=1}^{N} \int_{0}^{n_i} marginal\ WTP_i(x)dx \ ,$$

where marginal $WTP_i(x)$ is the i^{th} individual's marginal willingness to pay curve, n_i is the number of units of risk reduction conferred on the i^{th} exposed individual as a result of the pollution reduction, and N is the total number of exposed individuals.

The values of a statistical life implied by the value-of-life studies were derived from specific risk reductions. Implicit in applying these values to a situation involving possibly different risk reductions is the assumption that the marginal willingness to pay curve is horizontal – that is, that WTP for n units of risk reduction is n times WTP for one unit of risk reduction. If the marginal willingness to pay curve is horizontal, the integral in the above expression becomes a simple product of the number of units of risk reduction times the WTP per unit. The total mortality-related benefit (the expression above) then becomes:

$$\sum_{i=1}^{N} (number\ of\ units\ of\ risk\ reduction)_i \cdot \left(\frac{WTP_i}{unit\ of\ risk\ reduction} \right).$$

If different subgroups of the population have substantially different WTPs for a unit risk reduction and substantially different numbers of units of risk reduction conferred on them, then estimating the total social benefit by multiplying the population mean WTP (MWTP) to save a statistical life times the predicted number of statistical lives saved could yield a biased result. Suppose, for example, that older individuals' WTP per unit risk reduction is less than that of younger individuals (e.g., because they have fewer years of expected life to lose). Then the total benefit will be less than it would be if everyone's WTP were the same. In addition, if each older individual has a larger number of units of risk reduction conferred on him (because a given pollution reduction results in a greater absolute reduction in risk for older individuals than for younger individuals), this, in combination with smaller WTPs of older individuals, would further reduce the total benefit.

While the estimation of WTP for a market good (i.e., the estimation of a demand schedule) is not a simple matter, the estimation of WTP for a non-market good, such as a decrease in the risk of having a particular health problem, is substantially more difficult. Estimation of WTP for decreases in very specific health risks (e.g., WTP to decrease the risk of a day of coughing or WTP to decrease the risk of admission to the hospital for respiratory illness) is further limited by a paucity of information.[7] Derivation of the dollar value estimates discussed below was often limited by available information.

Change Over Time in WTP in Real Dollars

The WTP for health-related environmental improvements (in real dollars) could change between now and the years 2010 and 2020. If real income increases between now and the year 2010, for example, it is reasonable to expect that WTP, in real dollars, would also increase. Below we summarize the evidence regarding this effect, however we do not adjust our results in this analysis, because of the uncertainty regarding the size of the effect.

Based on historical trends, the U.S. Bureau of Economic Analysis projects that, for the United States as a whole as well as for regions and states within the U.S., mean per capita real income will increase. For the U.S. as a whole, for example, mean per capita personal income is projected to increase by about 16 percent from 1993 to 2005 (U.S. Bureau of Economic Analysis, 1995).

The mean WTP in the population is the correct measure of the value of a health problem avoided, and that WTP is a function of income. If the mean per capita real income rises by the year 2010, the mean WTP would probably rise as well. While this is most likely true, the degree to which mean WTP rises with a rise in mean per capita income is unclear unless the elasticity of WTP with respect to changes over time in real income is 1.0.

There is some evidence (Loehman and De, 1982; Mitchell and Carson, 1986; Alberini et al., 1997) that the elasticity of WTP for health-related environmental improvements with respect to real income is less than 1.0, possibly substantially so. If this is the case, then changes in mean income cannot be readily translated into corresponding changes in mean WTP. Although an increase in mean income is likely to imply an increase in mean WTP, the degree of the increase cannot be ascertained from information only about the means.

Several factors, in addition to real income, that could affect the estimated benefit associated with reductions in air pollution concentrations could also change in the future Demographic characteristics of exposed populations could change. Technological advances could change both the nature of precursor emissions to the ambient air and the susceptibility of individuals to air pollution. Any such changes would be reflected in C-R functions that differ from those that describe current relationships between ambient concentrations and the various health endpoints. While adjustments of WTP to reflect changes in real income are of interest, such adjustments would by no means necessarily reflect all possible changes that could affect the future benefits of reduced air pollution.

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[7] Some health effects, such as technical measures of pulmonary functioning (e.g., forced expiratory volume in one second) are frequently studied by epidemiologists, but there has been very little work by economists on valuing these changes (e.g., Ostro et al., 1989).

Adjusting Benefits Estimates to Year 1999 Dollars

This section describes the methods used to convert benefits estimates to constant 1999 dollars. This is necessary because some of the WTP estimates that we use are measured in dollars from different years. The method that we use depends on the basis of the benefits estimates. Table 4-1 delineates these bases.

Table 4-1 Bases of Benefits Estimation

Basis of Benefit Estimation	Benefit Endpoints
Cost of illness	Hospital admissions avoided
Direct estimates of WTP	Statistical lives saved Chronic bronchitis Morbidity endpoints using WTP
Earnings	Work loss days (WLDs) avoided

Benefits estimates based on cost-of-illness have been adjusted by using the consumer price indexes (CPI-Us) for medical care. Because increases in medical costs have been significantly greater than the general rate of inflation, using a general inflator (the CPI-U for “all items” or some other general inflator) to adjust from previous year dollars to 1999 dollars would downward bias cost-of-illness estimates in 1999 dollars.

Benefits estimates based directly on estimates of WTP have been adjusted using the CPI-U for “all items.” The CPI-Us, published by the U.S. Dept. of Labor, Bureau of Labor Statistics, can be found in Council of Economic Advisers (2004, Table B-58). An overview of the adjustments from 1990 to 1999 dollars for WTP-based and cost-of-illness based valuations is given in Table 4-2.

Table 4-2 Consumer Price Indexes Used to Adjust WTP-Based and Cost-of-Illness-Based Benefits Estimates from 1990 Dollars to 1999 Dollars

	1990 (1)	1999 (2)	Adjustment Factor [a] (2)/(1)	Relevant Endpoints
CPI-U for "All Items" [b]	130.7	166.6	1.275	WTP-based valuation: 1. Statistical lives saved [c] 2. Chronic bronchitis 3. Morbidity endpoints using WTP [d]
CPI-U for Medical Care [b]	162.8	250.6	1.539	Cost-of-illness based valuation: Hospital admissions avoided [e]

[a] Benefits estimates in 1990 dollars are multiplied by the adjustment factor to derive benefits estimates in 1999 dollars.

[b] Source: Dept. of Labor, Bureau of Labor Statistics; reported in Council of Economic Advisers (2000, Table B-58)

[c] Adjustments to 1990 $ were originally made by Industrial Economics Inc. using the CPI-U for "all items" (IEc1992).

[d] Adjustments of WTP-based benefits for morbidity endpoints to 1990 $ were originally made by Industrial Economics Inc. (1993) using the CPI-U for "all items."

[e] Adjustments of cost-of-illness based estimates of all hospital admissions avoided to 1990 $ were made by Abt Associates Inc. in previous analyses, such as the NAAQS RIA (U.S. EPA, 1997).

Benefit estimates for work loss days (WLDs) avoided have in past analyses been based on either the mean or median daily wage. For this analysis, the valuation of the benefit of avoiding a work loss day used the median daily income rather than the mean, consistent with economic welfare theory. The income distribution in the United States is highly skewed, so that the mean income is substantially larger than the median income. However, the incomes of those individuals who lose work days due to pollution are not likely to be a random sample from this income distribution. In particular, the probability of being drawn from the upper tail of the distribution is likely to be substantially less than the probability mass in that tail. To reflect this likelihood, we used the median income rather than the mean income as the value of a work loss day. This is explained more fully below in the section on valuing work loss days.

The benefits estimates for WLDs avoided can be put into 1999 dollars in several ways. One approach is to obtain the 1998 median weekly earnings (the most up-to-date measure of earnings available), divide by five to derive the median daily earnings, and adjust the median earnings from 1998 to 1999 dollars. This is an alternative to relying on adjustments from 1990 to 1999 dollars. The median weekly earnings of full-time wage and salary workers in 1998 was $523 (U.S. Bureau of the Census 1998, Table 696). This implies a median daily earnings of $104.6, or rounded to the nearest dollar, $105. Alternatively, we can adjust the median daily wage for 1990 to 1999 dollars, using the CPI-U for "all items." The result turns out to be the same. The adjustment factor (the ratio of the 1999 CPI-U to the 1990 CPI-U) is 1.275. Applied to the median daily earnings of $82.4 in 1990, the median daily earnings in 1997 would be $105.1, or rounded to the nearest dollar, $105.

Aggregation of Monetized Benefits

The total monetized benefit associated with attaining a given set of pollution changes in a given location is just the sum of the non-overlapping benefits associated with these changes. In theory, the total health-related social value of the reduction in pollution concentrations is:

$$\sum_{i=1}^{N} \sum_{j=1}^{J} WTP_i\left(B_{i,j}\right) ,$$

where B_{ij} is the benefit related to the j^{th} health endpoint (i.e., the reduction in probability of having to endure the j^{th} health problem) conferred on the i^{th} individual by the reduction in pollution concentrations, and $WTP_i(B_{ij})$ is the i^{th} individual's WTP for that benefit.

As stated earlier, the reduction in probability of each health problem for each individual is not known, nor do we know each individual's WTP for each possible benefit he or she might receive. Therefore, in practice, benefits analysis estimates the value of a *statistical* health problem avoided. The benefit in the k^{th} location associated with the j^{th} health endpoint is just the change in incidence of the j^{th} health endpoint in the k^{th} location, Δy_{jk}, times the value of an avoided occurrence of the j^{th} health endpoint.

Assuming that WTP to avoid the risk of a health effect varies from one individual to another, there is a *distribution* of WTPs to avoid the risk of that health effect. This population distribution has a mean. It is this population mean of WTPs to avoid or reduce the risk of the j^{th} health effect, $MWTP_j$, that is the appropriate value in the benefit analysis.[8] The monetized benefit associated with the j^{th} health endpoint resulting from attainment of standard(s) in the k^{th} location, then, is:

$$benefit_{jk} = \Delta y_{jk} \cdot MWTP_j$$

and total monetized benefit in the k^{th} location (TMB_k) may be written as the sum of the monetized benefits associated with all non-overlapping endpoints:

$$TMB_k = \sum_{j=1}^{N} \Delta y_{jk} \cdot MWTP_j \; .$$

The location- and health endpoint-specific incidence change, Δy_{jk}, is modeled as the population response to the change in pollutant concentrations in the k^{th} location. Assuming a log-linear C-R function, the change in incidence of the j^{th} health endpoint in the k^{th} location corresponding to a change in PM, ΔPM_k, in the k^{th} location is:

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[8]The population of interest has not been defined. In a location-specific analysis, the population of interest is the population in that location. The MWTP is ideally the mean of the WTPs of all individuals in the location. There is insufficient information, however, to estimate the MWTP for any risk reduction in any particular location. Instead, estimates of MWTP for each type of risk reduction will be taken to be estimates of the MWTP in the United States as a whole, and it will be assumed that $MWTP_i$, i=1, ..., N in each location is approximately the same as in the United States as a whole.

$$\Delta y_{jk} = y_{jk} \cdot \left(e^{b_{jk} \cdot \Delta PM_k} - 1 \right) ,$$

where y_{jk} is the baseline incidence of the j^{th} health endpoint in the k^{th} location and β_{jk} is the value of β_j , the coefficient of PM in the C-R relationship between PM and the j^{th} health endpoint, in the k^{th} location.

This approach assumes that there is a *distribution* of β_j's across the United States, that is, that the value of β_j in one location may not be the same as the value of β_j in another location. The value of β_j in the k^{th} location is denoted as β_{jk} .

The total PM-related monetized benefit for the k^{th} location can now be rewritten as:

$$TMB_k = \sum_{j=1}^{N} y_{jk} \cdot \left(e^{b_{jk} \cdot \Delta PM_k} - 1 \right) \cdot MWTP_j \ ,$$

The total monetized PM-related benefit to be estimated for a location is thus a function of 2N parameters: the coefficient of PM, β_{jk} , in the C-R function for the j^{th} health endpoint, for j=1, ..., N, specific to the k^{th} location, and the population mean WTP to reduce the risk of the j^{th} health endpoint, $MWTP_j$, j=1, ..., N.

The above model assumes that total monetized benefit is the sum of the monetized benefits from all non-overlapping endpoints. If two or more endpoints were overlapping, or if one was contained within the other (as, for example, hospital admissions for Chronic Obstructive Pulmonary Disease (COPD) is contained within hospital admissions for "all respiratory illnesses"), then adding the monetized benefits associated with those endpoints would result in double (or multiple) counting of monetized benefits. If some endpoints that are not contained within endpoints included in the analysis are omitted, then the aggregated monetized benefits will be less than the total monetized benefits.

The total monetized benefit (TMB) is the sum of the total monetized benefits achieved in each location:

$$TMB = \sum_{k=1}^{K} TMB_k$$

where TMB_k denotes the total monetized benefit achieved in the k^{th} location, and K is the number of locations.

Theoretically, the nation-wide analysis could use location-specific C-R functions to estimate location-specific benefits. Total monetized benefits (TMB), then, would just be the sum of these location-specific benefits:

$$TMB = \sum_{k=1}^{K} TMB_k = \sum_{k=1}^{K} \sum_{j=1}^{N} y_{jk} \cdot \left(e^{b_{jk} \cdot \Delta PM_k} - 1 \right) \cdot MWTP_j \ ,$$

There are many locations in the United States, however, and the individual location-specific values of β_j (the β_{jk}'s) are not known.[9] Since the national incidence of the j^{th} health endpoint attributed to PM, I_j , is a continuous function of the set of β_{jk}'s, that is, since:

$$I_j = \sum_{k=1}^{K} \Delta y_{jk} = \sum_{k=1}^{K} y_{jk} \cdot \left(e^{b_{jk} \cdot \Delta PM_k} - 1\right) ,$$

is a continuous function of the set of β_{jk}'s, there is some value of β_j , which can be denoted β_j*, that, if applied in *all* locations, would yield the same result as the proper set of location-specific β_{jk}'s. This follows from the Intermediate Value Theorem. While β_j* will result in overestimates of incidence in some locations, it will result in underestimates in others. If β_j* is applied in all locations, however, the *total regional* change in incidence will be correct. That is,

$$I_j = \sum_{k=1}^{K} \Delta y_{jk} = \sum_{k=1}^{K} y_{jk} \cdot \left(e^{b_j^* \cdot \Delta PM_k} - 1\right) ,$$

$$= \sum_{k=1}^{K} y_{jk} \cdot \left(e^{b_{jk} \cdot \Delta PM_k} - 1\right) \ .$$

The total regional monetized PM-related benefit can now be rewritten as:

$$TMB_k = \sum_{j=1}^{N} \sum_{k=1}^{K} y_{jk} \cdot \left(e^{b_j^* \cdot \Delta PM_k} - 1\right) \cdot MWTP_j \ .$$

The total regional monetized (PM-related) benefit is thus a function of 2N population means: the β* for the j^{th} health endpoint (β_j* , for j=1, ..., N) and the population mean WTP to reduce the risk of the j^{th} health endpoint ($MWTP_j$, j=1, ..., N).

Both the endpoint-specific coefficients (the ÿ$_j$'s) and the endpoint-specific mean WTPs (the $MWTP_j$'s) are uncertain. One approach to estimating the total monetized benefit is to simply use the mean values of the endpoint-specific coefficients and mean WTPs in the above formula. We term this approach the "simple mean." Alternatively, we can characterize not only the mean total monetized benefit but the distribution of possible values of total monetized benefit, using a Monte Carlo approach. The Monte Carlo approach has three steps. First, in each of 5000 iterations, we randomly select a value from the distribution of (national) incidence change of the health effect. Second, we randomly select a value from the distribution

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[9]This may also be true of the y_{ij}'s. It may be desirable to apply the uncertainty analysis used for the β's to these population parameters as well. In the current discussion, however, it is assumed that the location-specific incidences are known and therefore have no uncertainty associated with them. It is also assumed that $MWTP_i$ is the same in all locations.

of unit dollar values for that health effect. And third, we multiply the two values. The result is a distribution of (5000) monetized benefits associated with the given health effect. From this distribution, we present the mean as well as the 5th and 95th percentiles. We discuss the background of the Monte Carlo in the following sub-section.

Characterization of Uncertainty

In any complex analysis using estimated parameters and inputs from numerous different models, there are likely to be many sources of uncertainty. This analysis is no exception. There are many inputs that are used to derive the final estimate of benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological estimates of C-R functions, estimates of values (both from WTP and cost-of-illness studies), population estimates, income estimates, and estimates of the future state of the world, i.e. regulations, technology, and human behavior. Each of these inputs may be uncertain, and depending on their location in the benefits analysis, may have a disproportionately large impact on final estimates of total benefits. For example, emissions estimates are used in the first stage of the analysis. As such, any uncertainty in emissions estimates will be propagated through the entire analysis. When compounded with uncertainty in later stages, small uncertainties in emissions can lead to much larger impacts on total benefits.

Table 4-3 summarizes the wide variety of sources for uncertainty in this analysis. Some key sources of uncertainty in each stage of the benefits analysis are:

- gaps in scientific data and inquiry
- variability in estimated relationships, such as C-R functions, introduced through differences in study design and statistical modeling
- errors in measurement and projection for variables such as population growth rates
- errors due to misspecification of model structures, including the use of surrogate variables, such as using PM_{10} when $PM_{2.5}$ is not available, excluded variables, and simplification of complex functions
- biases due to omissions or other research limitations.

In some cases, it was not possible to quantify uncertainty. For example, many benefits categories, while known to exist, do not have enough information available to provide a quantified or monetized estimate. The uncertainty regarding these endpoints is such that we could determine neither a primary estimate nor a plausible range of values. Of the primary endpoints we do quantify, a number of alternative measures of mortality incidence can be calculated. We present the full suite of alternative mortality calculations as a way to address the range of plausible mortality incidence estimates. This is discussed in greater detail in Chapter 5.

A final approach to measuring uncertainty is through probabilistic assessments where statistical uncertainty bounds are calculated for each endpoint. We discuss statistical uncertainty bounds in the following section.

Table 4-3 Key Sources of Uncertainty in the Benefit Analysis

1. Uncertainties Associated With Concentration-Response Functions
-The value of the PM-coefficient in each C-R function. -Application of a single C-R function to pollutant changes and populations in all locations. -Similarity of future year C-R relationships to current C-R relationships. -Correct functional form of each C-R relationship. -Extrapolation of C-R relationships beyond the range of PM concentrations observed in the study.
2. Uncertainties Associated With PM Concentrations
-Estimating future-year baseline daily PM concentrations. -Estimating the change in PM resulting from the control policy.
3. Uncertainties Associated with PM Mortality Risk
-No scientific literature supporting a direct biological mechanism for observed epidemiological evidence. -Direct causal agents within the complex mixture of PM responsible for reported health effects have not been identified. -The extent to which adverse health effects are associated with low level exposures that occur many times in the year versus peak exposures. -Possible confounding in the epidemiological studies of $PM_{2.5}$, effects with other factors (e.g., other air pollutants, weather, indoor/outdoor air, etc.). -The extent to which effects reported in the long-term studies are associated with historically higher levels of PM rather than the levels occurring during the period of study. -Reliability of the limited ambient $PM_{2.5}$ monitoring data in reflecting actual $PM_{2.5}$ exposures.
4. Uncertainties Associated With Possible Lagged Effects
-What portion of the PM-related long-term exposure mortality effects associated with changes in annual PM levels would occur in a single year, and what portion might occur in subsequent years.
5. Uncertainties Associated With Baseline Incidence Rates
-Some baseline incidence rates are not location-specific (e.g., those taken from studies) and may therefore not accurately represent the actual location-specific rates. -Current baseline incidence rates may not well approximate what baseline incidence rates will be in the year 2030. -Projected population and demographics -- used to derive incidences – may not well approximate future-year population and demographics.
6. Uncertainties Associated With Economic Valuation
-Unit dollar values associated with health are only estimates of mean WTP and therefore have uncertainty surrounding them. -Mean WTP (in constant dollars) for each type of risk reduction may differ from current estimates due to differences in income or other factors.
7. Uncertainties Associated With Aggregation of Monetized Benefits
-Health benefits estimates are limited to the available C-R functions. Thus, unquantified benefit categories will cause total benefits to be underestimated.

Statistical Uncertainty Bounds

Although there are several sources of uncertainty affecting estimates of endpoint-specific benefits, the sources of uncertainty that are most readily quantifiable in this analysis are the incidence changes (deriving from uncertainty about the C-R relationships) and uncertainty about unit dollar values. The total dollar benefit associated with a given endpoint depends on how much the endpoint will change due to the final standard (e.g., how many premature deaths will be avoided) and how much each unit of change is worth (e.g., how much a premature death avoided is worth).[10] Based on these distributions, we provide estimates of the 5th and 95th percentile values of the distribution of estimated benefits. However, we hasten to add that this omits important sources of uncertainty, such as the contribution of air quality changes, baseline population incidences, projected populations exposed, transferability of the C-R function to diverse locations, and uncertainty about premature mortality. Thus, a confidence interval based on the standard error would provide a misleading picture about the overall uncertainty in the estimates. The empirical evidence about uncertainty is presented where it is available.

Both the uncertainty about the incidence changes and uncertainty about unit dollar values can be characterized by *distributions*. Each "uncertainty distribution" characterizes our beliefs about what the true value of an unknown (e.g., the true change in incidence of a given health effect) is likely to be, based on the available information from relevant studies.[11] Unlike a sampling distribution (which describes the possible values that an *estimator* of an unknown value might take on), this uncertainty distribution describes our beliefs about what values the unknown value itself might be. Such uncertainty distributions can be constructed for each underlying unknown (such as a particular pollutant coefficient for a particular location) or for a function of several underlying unknowns (such as the total dollar benefit of a regulation). In either case, an uncertainty distribution is a characterization of our beliefs about what the unknown (or the function of unknowns) is likely to be, based on all the available relevant information. Uncertainty statements based on such distributions are typically expressed as 90 percent credible intervals. This is the interval from the fifth percentile point of the uncertainty distribution to the ninety-fifth percentile point. The 90 percent credible interval is a "credible range" within which, according to the available information (embodied in the uncertainty distribution of possible values), we believe the true value to lie with 90 percent probability.

The uncertainty about the total dollar benefit associated with any single endpoint combines the uncertainties from these two sources, and is estimated with a Monte Carlo method. In each iteration of the Monte Carlo procedure, a value is randomly drawn from the incidence distribution and a value is randomly drawn from the unit dollar value distribution, and the total dollar benefit for that iteration is the product of the two.[12] If this is repeated for many (e.g., thousands of) iterations, the distribution of total dollar benefits associated with the endpoint is generated.

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[10] Because this is a regional analysis in which, for each endpoint, a single C-R function is applied everywhere, there are two sources of uncertainty about incidence: (1) statistical uncertainty (due to sampling error) about the true value of the pollutant coefficient in the location where the C-R function was estimated, and (2) uncertainty about how well any given pollutant coefficient approximates β^*.

[11] Although such an "uncertainty distribution" is not formally a Bayesian posterior distribution, it is very similar in concept and function (see, for example, the discussion of the Bayesian approach in Kennedy1990, pp. 168-172).

[12] This method assumes that the incidence change and the unit dollar value for an endpoint are stochastically independent.

Using this Monte Carlo procedure, a distribution of dollar benefits may be generated for each endpoint. The mean and median of this Monte Carlo-generated distribution are good candidates for a point estimate of total monetary benefits for the endpoint. As the number of Monte Carlo draws gets larger and larger, the Monte Carlo-generated distribution becomes a better and better approximation to the underlying uncertainty distribution of total monetary benefits for the endpoint. In the limit, it is identical to the underlying distribution.

Unquantified Benefits

In considering the monetized benefits estimates, the reader should remain aware of the limitations. One significant limitation of benefits analyses is the inability to quantify many of the PM adverse effects. For many effects, reliable C-R functions and/or valuation functions are not currently available such as infant mortality. In general, if it were possible to monetize these benefits categories, the benefits estimates presented here would increase.

5 Health Benefits

The most significant monetized benefits of reducing ambient concentrations of PM are attributable to reductions in health risks associated with air pollution. This Chapter describes individual effects and the methods used to quantify and monetize changes in the expected number of incidences of various health effects.

We estimate the incidence of adverse health effects using PM-based C-R functions. The changes in incidence of PM-related adverse health effects and corresponding monetized benefits associated with these changes are estimated separately. Table 5-1 presents the PM-related health endpoints included in this analysis, and Table 5-2 presents the unit monetary values for each of these endpoints and associated uncertainty distributions. Appendix A presents the functional forms for each C-R function and their derivation.

Below, we discuss for each endpoint issues relating to the calculation of changes in incidence, the monetization of these changes, and the characterization of the uncertainty surrounding our estimates. For some of the endpoint-pollutant combinations, there are several epidemiological studies that have estimated C-R functions. In these cases, we pooled the information from the multiple studies. That is, we based the estimation of the change in incidence and the corresponding monetized value of that change on a synthesis of the information from the available studies.

Table 5-1 PM-Related Health Endpoints

Endpoint	Population	PM Measure	Study
Mortality			
Associated with long-term exposure	Ages 30+	$PM_{2.5}$	(Krewski et al., 2000), reanalysis of Pope et al., 1995, using the annual mean and all-cause mortality, 63 city Dichotomous samplers.
Chronic Illness			
Chronic Bronchitis	Ages 27+	$PM_{2.5}$	Abbey et al. (1995c)
Heart Attacks			
Acute Myocardial Infarction(Non-fatal)	Ages 18+	$PM_{2.5}$	Peters et al. (2001)
Hospital Admissions			
Chronic Lung Disease Less Asthma(ICD codes 490-492, 494-496)	Ages 18-64	$PM_{2.5}$	Moolgavkar (2000c)
Asthma (ICD code 493)	< 65	$PM_{2.5}$	Sheppard et al. (1999)
Pneumonia (ICD-9 codes 480-487)	Ages 65+	$PM_{2.5}$	Lippmann et al. (2000, Detroit)
Chronic Lung Disease (ICD codes 490-496)	Ages 65+	$PM_{2.5}$	Pooled Estimate: Lippmann et al. (2000), Moolgavkar (2000b)
Cardiovascular (ICD codes 390-409, 411-429)	Ages 20-64	$PM_{2.5}$	Moolgavkar (2000a, Los Angeles)
Cardiovascular ((ICD codes 390-409, 411-429)	age 65+	$PM_{2.5}$	Pooled Estimate: Moolgavkar (2000a), Lippmann et al. (2000)
Asthma-related ER visits (ICD code 493)	< 18	$PM_{2.5}$	Norris et al. (1999)
Respiratory Symptoms/Illnesses Not Requiring Hospitalization			
Acute bronchitis	Ages 8-12	$PM_{2.5}$	Dockery et al. (1996)
Lower respiratory symptoms (LRS)	Ages 7-14	$PM_{2.5}$	Schwartz et al. (1994)
Upper respiratory symptoms (URS)	Asthmatics, ages 9-11	PM_{10}	Pope et al. (1991)
Minor restricted activity day (MRAD) (adjusted for asthma attacks)	Ages 18-65	$PM_{2.5}$ (estimated)	Ostro and Rothschild (1989)
Work loss days (WLDs)	Ages 18-65	$PM_{2.5}$	Ostro (1987)

[a] The incidence changes, and the associated monetized benefits, predicted by two studies are pooled. The separate studies and the method of pooling are described below.

[b] The pooled estimate, based on distributed lag models in each of 14 cities, is used because the estimated coefficients based on pooling are substantially more stable than the individual city-specific estimates.

Table 5-2 Unit Values for Economic Valuation of Health Endpoints (1999 $)

Health Endpoint	Mean Estimate [a]	Uncertainty Distribution [a]
Mortality		
Value of a statistical life	$6.12 million per statistical life [b]	Weibull distribution, mean = $6.12 million; std. dev. = $4.13 million.
Chronic Bronchitis		
WTP approach	$331,000 per case	A Monte Carlo-generated distribution, based on three underlying distributions.
Heart Attacks		
Acute Myocardial Infarction (Non-fatal)	Age / Per Case 18-24 $63,325 25-44 $71,755 45-54 $75,751 55-64 $135,148 65+ $63,325	
Hospital Admissions		
Chronic Lung Disease Less Asthma(ICD codes 490-492, 494-496) (Ages 20-64)	$11,333 per admission	
Asthma (ICD code 493)	$7,467 per admission	
Pneumonia (ICD codes 480-487) (Ages 65+)	$17,106 per admission	
Chronic Lung Disease (ICD codes 490-496) (Ages 65+)	$13,083 per admission	
Cardiovascular(ICD codes 390-429)	Age 65+ $20,344 20-64 $21,864	
Asthma-related ER visits (Ages < 18)	$275 per visit	
Respiratory Ailments Not Requiring Hospitalization		
Acute bronchitis	$344 per case	
Lower resp. Symptoms	$15.30 per symptom-day	Continuous uniform distribution over [$6.37, $24.22].
Upper resp. Symptoms	$24.23 per symptom-day	Continuous uniform distribution over [$8.93,$42.06].
Minor respiratory activity day (MRAD)	$48.43 per day	Triangular distribution centered at $48.43 over [$20.34, $77.76].
Work loss days	$106 per day	None available

[a] The derivation of each of the estimates is discussed in the text.

[b] An adjustment for lagged mortality, discussed in the text, is used in this analysis. The lag-adjusted value of a statistical life is approximately 92% of the full value presented here.

[c] Standard errors were not available. However, the sample sizes on which these estimates (from the Agency for Healthcare Research and Policy's Healthcare Cost and Utilization Project) are very large and the standard errors are therefore negligible.

Health Endpoint	Mean Estimate [a]	Uncertainty Distribution [a]

[d] Cost of illness unit dollar values were derived for each separate set of ICD codes for which a C-R model was estimated. These are given below.

Premature Mortality

Health researchers have consistently linked air pollution, especially PM, with excess mortality. Although a number of uncertainties remain to be addressed by continued research (National Research Council, 1998), a substantial body of published scientific literature recognizes a correlation between elevated PM concentrations and increased mortality rates.

There are two types of exposure to elevated levels of air pollution that may result in premature mortality. Acute (short-term) exposure (e.g., exposure on a given day) to peak pollutant concentrations may result in excess mortality on the same day or within a few days of the elevated exposure. Chronic (long-term) exposure (e.g., exposure over a period of a year or more) to levels of pollution that are generally higher may result in mortality in excess of what it would be if pollution levels were generally lower. The excess mortality that occurs will not necessarily be associated with any particular episode of elevated air pollution levels.

Both long and short-term exposures to ambient levels of air pollution have been associated with increased risk of premature mortality. It is clearly an important health endpoint because of the size of the mortality risk estimates, the serious nature of the effect itself, and the high monetary value ascribed to avoiding mortality risk. Because of the importance of this endpoint and the considerable uncertainty among economists and policymakers as to the appropriate way to estimate mortality risks, this section discusses some of the issues surrounding the estimation of premature mortality.

Table 5-3 Alternative Mortality Concentration-Response Functions

Endpoint	Population	PM Indicator	Study
Associated with long-term exposure	Ages 30+	$PM_{2.5}$	(Krewski et al., 2000), reanalysis of Pope et al., 1995, using the annual mean and all-cause mortality, 63 city Dichotomous sampler
Associated with long-term exposure	Ages 25+	$PM_{2.5}$	Krewski et al., 2000 - Reanalysis of Dockery et al. (1993)
Associated with long-term exposure(Lung Cancer)	Ages 30+	$PM_{2.5}$	Pope et al., 2002 - Based on ACS Cohort: Mean $PM_{2.5}$

Short-Term Versus Long-Term Studies

Long-term studies (e.g., Krewski et al., 2000, and Pope et al., 1995) estimate the association between long-term (chronic) exposure to air pollution and the survival of members of a large study population over an extended period of time. Such studies examine the health endpoint of concern in relation to the general long-term level of the pollutant of concern, for example, relating annual mortality to some measure of annual pollutant level. Daily peak concentrations would impact the results only insofar as they affect the measure of long-term (e.g., annual) pollutant concentration. In contrast, short-term studies relate daily levels of the pollutant to daily mortality. By their basic design, daily studies can detect acute effects but cannot detect the effects of long-term exposures. A chronic exposure study design (a prospective cohort study, such as the Pope study(1995) or the Krewski et al (2000)) is best able to identify the long-term exposure effects, and may detect some of the short-term exposure effects as well. Because a long-term exposure study may detect some of the same short-term exposure effects detected by short-term studies, including both types of study in a benefit analysis would likely result in some degree of double counting of benefits. While the long-term study design is preferred, these types of studies are expensive to conduct and consequently there are relatively few well designed long-term studies. To avoid double counting, as well as issues involving short-term harvesting(discussed below in detail), we have used only long-term studies for this analysis.

Degree of Prematurity of Mortality

It is possible that the short-term studies are detecting an association between PM and mortality that is primarily occurring among terminally ill people. Critics of the use of short-term studies for policy analysis purposes correctly point out that an added risk factor that results in terminally ill people dying a few days or weeks earlier than they otherwise would have (referred to as "short-term harvesting") is potentially included in the measured PM mortality "signal" detected in such a study. While some of the detected excess deaths may have resulted in a substantial reduction in lifespan, others may have resulted in a relatively small decrease in lifespan. However, there is little evidence to bear on this question. Studies by Spix et al (1993) and Pope et al. (1992) yield conflicting evidence, suggesting that harvesting may represent anywhere from zero to 50 percent of the deaths estimated in short-term studies. A recent study by Zeger et al. (1999), that focused exclusively on this issue, reported that short-term harvesting may be a quite small fraction of mortality.[13]

It is not likely, however, that the excess mortality reported in a long-term prospective cohort studies like Pope et al. (1995) or Krewski et al. (2000), contain any significant amount of this short-term harvesting. The Cox proportional hazard statistical model used in the Pope study examines the question of survivability throughout the study period (ten years). Deaths that are premature by only a few days or weeks within the ten-year study period (for example, the deaths of terminally ill patients, triggered by a short duration PM episode) are likely to have little impact on the calculation of the average probability of surviving the entire ten-year interval.

In developing and improving the methods for estimating and valuing the potential reductions in mortality risk over the years, EPA has consulted with a panel of the Science Advisory Board(SAB). That panel recommended use of long-term prospective cohort studies in estimating mortality risk reduction (U.S. EPA, 1999a). This recommendation has been confirmed by a recent report from the National Research Council, which stated that "it is essential to use the cohort studies in benefits analysis to capture all important effects from air pollution exposure (National Research Council, 2002, p. 108). The Krewski et al. analysis also includes a broader geographic scope than the original study (63 cities versus 50). The SAB has recently agreed with EPA's selection of this specification for use in analyzing mortality benefits of PM reductions (U.S. EPA, 2001).

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[13]Zeger et al. (1999, p. 171) reported that: "The TSP-mortality association in Philadelphia is inconsistent with the harvesting-only hypothesis, and the harvesting-resistant estimates of the TSP relative risk are actually larger – not smaller – than the ordinary estimates."

It is not possible to estimate with any degree of confidence how premature is the PM-related mortality. Making such an estimate requires considerable more understanding of the relationships between PM and human health than is currently available. As the amount of prematurity is potentially a very important issue for public policy, however, EPA did develop an estimate. Using an approach developed by the World Health Organization, the EPA estimated that "The average number of life-years lost by individuals dying prematurely from exposure to PM is 14 years." (*Final Report to Congress on Benefits and Costs of the Clean Air Act, 1970 to 1990*", EPA 410-R-97-002 p. I-23.

Estimating PM-Related Premature Mortality

The benefits analysis estimates $PM_{2.5}$ -related mortality using the C-R function estimated by Krewski et al. (2000). This study is a reanalysis of (Pope et al., 1995), which estimated the association between long-term (chronic) exposure to $PM_{2.5}$ and the survival of members of a large study population. Our decision to use Pope et al. (1995) in previous benefits analyses reflected the Science Advisory Board's explicit recommendation for modeling the mortality effects of PM in both the§812 Retrospective Report to Congress and the §812 Prospective Report (U.S. EPA, 1999a, p. 12). An advantage of Krewski et al. (2000) over Pope et al. (1995) is that Krewski et al.'s (2000) reanalysis of the Pope data uses the annual mean $PM_{2.5}$ concentration rather than the annual median. Because the mean is more readily affected by high PM values than is the median, if high PM days are actually important in causing premature mortality, the annual mean may be a preferable measure of long-term exposure than the median. However, estimates of annual mean levels are inherently less stable than annual median estimates, and are more sensitive to the estimates on the highly polluted days. Specifically, we use the Krewski results (Table 31, Krewski et al. (2000)) based on dichotomous samplers in 63 cities (rather than the 50 cities used in the Pope et al. $PM_{2.5}$ analysis).

The Krewski et al. (2000) long-term study is selected for use in the benefits analysis instead of short-term (daily pollution) studies for a number of reasons. It is used alone– rather than considering the total effect to be the sum of estimated short-term and long-term effects– because summing creates the possibility of double-counting a portion of PM-related mortality. The Krewski et al. study and the Pope study it reanalyzes are considered preferable to other available long-term studies because they use better statistical methods, have a much larger sample size, and more locations (63 cities) in the United States, than other studies. We also consider the Krewski study preferable to the original Pope et al. (1995) study because it uses the annual mean $PM_{2.5}$ rather than the median.

It is unlikely that the Krewski et al. study contains any significant amount of short-term harvesting. First, the health status of each individual tracked in the study is known at the beginning of the study period. Persons with known pre-existing serious illnesses were excluded from the study population. Second, the statistical model used in the Krewski and Pope studies examines the question of survivability throughout the study period (ten years). Deaths that are premature by only a few days or weeks within the ten-year study period (for example, the deaths of terminally ill patients, triggered by a short duration PM episode) are likely to have little impact on the calculation of the average probability of surviving the entire ten year interval. In relation to the Krewski et al., 2000 - Reanalysis of Dockery et al. (1993), the Krewski et al. study 2000-Reanalysis of Pope et al.(1995) study found smaller increases in excess mortality for a given PM air quality change.

It is currently unknown whether there is a time lag (a delay between changes in PM exposures and changes in mortality rates) in the chronic PM/premature mortality relationship. The existence of such a lag is important for the valuation of premature mortality incidences because economic theory suggests that benefits occurring in the future should be discounted. Although there is no specific scientific evidence of the existence or structure of a PM effects lag, current scientific literature on adverse health effects, such as those associated with PM (e.g., smoking related disease) and the difference in the effect size between chronic exposure studies and daily mortality studies suggest that it is likely that not all incidences of premature mortality reduction associated with a given incremental change in PM exposure would occur in the same year as the exposure reduction. This same smoking-related literature implies that lags of up to a few years are plausible. Following explicit advice from the SAB, we assume a five-year lag structure, with 25 percent of premature deaths occurring in the first year, another 25 percent in the second year, and 16.7 percent in each of the remaining three years (EPA-SAB-COUNCIL-ADV-00-001, 1999). It should be noted that the selection of a five-year lag structure is not directly supported by any PM-specific literature. Rather, it is intended to be a best guess at the appropriate distribution of avoided incidences of PM-related mortality.

(1) Alternative Calculation: PM-Related Mortality Based on Krewski et al., 2000 - Reanalysis of Dockery et al. (1993)

Krewski, et al. (2000) also reanalyzed the data from another prospective cohort study (the Harvard "Six Cities Study") authored by Dockery et al. (1993). The Dockery et al. study used a smaller sample of individuals from fewer cities than the study by Pope et al. (1995); however, it features improved exposure estimates, a slightly broader study population (adults aged 25 and older), and a follow-up period nearly twice as long as that of Pope et al. The SAB has noted that "the [Harvard Six Cities] study had better monitoring with less measurement error than did most other studies" (U.S. EPA, 1999e, p. 10).

Some of the functions are based on changes in mean $PM_{2.5}$ concentrations while others are based on median $PM_{2.5}$ concentrations. Estimated reductions in premature mortality will depend on both the size of the C-R coefficient and the change in the relevant $PM_{2.5}$ metric (mean or median). We also estimated alternative premature mortality incidence using both non-accidental and all-cause mortality rates. In previous benefit analyses conducted for the EPA, premature mortality was calculated using non-accidental mortality rates. For the sake of comparability to previous analyses, we included estimates of premature mortality based on both rates.

(2) Alternative Calculation: Mortality, Lung Cancer (Pope et al., 2002) - Based on ACS Cohort: Mean $PM_{2.5}$

Pope et al. (2002) extends the original analysis by Pope et al. (1995) in a number of significant ways. Pope et al. (2002) had fifteen years of cohort data, as opposed to the eight years of data in the original work, and they used three different sets of years to measure mean $PM_{2.5}$ levels, as opposed to a single measure. The new set of results confirm the results of the earlier studies. In addition, the new set of results includes relative risk estimates for lung cancer and cardiopulmonary causes of death, in addition to all cause mortality.

Valuing Premature Mortality

The "statistical lives lost" approach to valuing premature mortality estimates the value of a statistical death to be $6.12 million (in 1999 $). We assume for this analysis that some of the incidences of premature mortality related to PM exposures occur in a distributed fashion over the five years following exposure (the five-year mortality lag). To take this into account in the valuation of reductions in premature mortalities, we apply an annual five percent discount rate to the value of premature mortalities occurring in future years.[14]

• **Statistical Lives Lost**

The "statistical lives lost" value of $6.12 million represents an intermediate value from a variety of estimates that appear in the economics literature, and is a value that EPA has frequently used. This estimate is the mean of a distribution fitted to the estimates from 26 value-of-life studies identified in the §812 study as "applicable to policy analysis." The approach and set of selected studies mirrors that of Viscusi (1992) (with the addition of two studies), and uses the same criteria used by Viscusi in his review of value-of-life studies. The $6.12 million estimate is consistent with Viscusi's conclusion (updated to 1999 $) that "most of the reasonable estimates of the value of life are clustered in the $3.84 to $8.93 million range." Uncertainty associated with the valuation of premature mortality is expressed through a Weibull distribution with a standard deviation of $4.13 million (IEc 1992, p. 2).

Five of the 26 studies are contingent valuation (CV) studies, which directly solicit WTP information from subjects; the rest are wage-risk studies, which base WTP estimates on estimates of the additional compensation demanded in the labor market for riskier jobs. The 26 studies are listed in Table 5-4. The references for all but Gegax et al. (1985) and V.K. Smith (1983) may be found in Viscusi (1992). Although each of the studies estimated the mean WTP (MWTP) for a given reduction in mortality risk, the amounts of reduction in risk being valued were not necessarily the same across studies, nor were they necessarily the same as the amounts of reduction in mortality risk that would actually be conferred by a given reduction in ambient concentrations. The transferability of estimates of the value of a statistical life from the 26 studies to this analysis rests on the assumption that, within a reasonable range, WTP for reductions in mortality risk is linear in risk reduction, or equivalently, that the marginal willingness to pay curve is horizontal within a reasonable range. For example, suppose a study estimates that the average WTP for a reduction in mortality risk of 1/100,000 is $30. Suppose, however, that the actual mortality risk reduction resulting from a given air quality improvement is 1/10,000. If WTP for reductions in mortality risk is linear in risk reduction, then a WTP of $30 for a reduction of 1/100,000 implies a WTP of $300 for a risk reduction of 1/10,000 (which is ten times the risk reduction valued in the study). Under the assumption of linearity, the estimate of the value of a statistical life does not depend on the particular amount of risk reduction being valued.

[14]The choice of a five percent discount rate is based on the technical recommendation of the SAB for computing the value of a statistical life-year (U.S. EPA, 1999c, p. 14).

Table 5-4 Summary of Mortality Valuation Estimates

Study	Type of Estimate	Valuation (millions 1999 $)
Kneisner and Leeth (1991) (US)	Labor Market	0.7
Smith and Gilbert (1984)	Labor Market	0.9
Dillingham (1985)	Labor Market	1.1
Butler (1983)	Labor Market	1.5
Miller and Guria (1991)	Contingent Valuation	1.6
Moore and Viscusi (1988)	Labor Market	3.2
Viscusi et al. (1991)	Contingent Valuation	3.4
Gegax et al. (1985; 1991)	Contingent Valuation	4.3
Marin and Psacharopoulos (1982)	Labor Market	3.5
Kneisner and Leeth (1991) (Australia)	Labor Market	4.3
Gerking et al. (1988)	Contingent Valuation	4.4
Cousineau et al. (1988; 1992)	Labor Market	4.6
Jones-Lee (1989)	Contingent Valuation	4.9
Dillingham (1985)	Labor Market	5.1
Viscusi (1978; 1979)	Labor Market	5.2
R.S. Smith (1976)	Labor Market	5.8
V.K. Smith (1983)	Labor Market	6.0
Olson (1981)	Labor Market	6.6
Viscusi (1981)	Labor Market	8.3
R.S. Smith (1974)	Labor Market	9.1
Moore and Viscusi (1988)	Labor Market	9.3
Kneisner and Leeth (1991) (Japan)	Labor Market	9.7
Herzog and Schlottman (1987; 1990)	Labor Market	11.6
Leigh and Folson (1984)	Labor Market	12.4
Leigh (1987)	Labor Market	13.3
Garen (1988)	Labor Market	17.2

Source: Viscusi (1992, Table 4.1).

Although the particular amount of mortality risk reduction being valued in a study may not affect the transferability of the WTP estimate from the study to this analysis, the characteristics of the study subjects and the nature of the mortality risk being valued in the study could be important. Certain characteristics of both the population affected and the mortality risk facing that population are believed to affect the MWTP to reduce the risk. The appropriateness of the MWTP estimates from the 26 studies for valuing the mortality-related benefits of reductions in ambient air concentrations therefore depends not only on the quality of the studies (i.e., how well they measure what they are trying to measure), but also on (1) the extent to which the subjects in the studies are similar to the population affected by changes in ambient air concentrations and (2) the extent to which the risks being valued are similar.

Focusing on the wage-risk studies, which make up the substantial majority of the 26 studies relied upon, the likely differences between (1) the subjects in these studies and the population affected by changes in air concentrations and (2) the nature of the mortality risks being valued in these studies and the nature of air pollution-related mortality risk are considered. The direction of bias in which each difference is likely to result is also considered.

Compared with the subjects in wage-risk studies, the population believed to be most affected by air pollution (i.e., the population that would receive the greatest mortality risk reduction associated with a given reduction in air concentrations) is, on average, older and probably more risk averse. For example, citing Schwartz and Dockery (1992) and Ostro et al. (1996), Chestnut (1995) estimated that approximately 85 percent of those who die prematurely from ambient air pollution-related causes are over 65. The average age of subjects in wage-risk studies, in contrast, is well under 65.

There is also reason to believe that those over 65 are, in general, more risk averse than the general population while workers in wage-risk studies are likely to be less risk averse than the general population. Although Viscusi's (1992) list of recommended studies excludes studies that consider only much-higher-than-average occupational risks, there is nevertheless likely to be some selection bias in the remaining studies -- that is, these studies are likely to be based on samples of workers who are, on average, more risk-loving than the general population. In contrast, older people as a group exhibit more risk averse behavior.

In addition, it might be argued that because the elderly have greater average wealth than those younger, the affected population is also wealthier, on average, than wage-risk study subjects, who tend to be blue collar workers. It is possible, however, that among the elderly it is largely the poor elderly who are most vulnerable to air pollution-related mortality risk (e.g., because of generally poorer health care). If this is the case, the average wealth of those affected by a reduction in air concentrations relative to that of subjects in wage-risk studies is uncertain.

The direction of bias resulting from the age difference is unclear, particularly because age is confounded by risk aversion (relative to the general population). It could be argued that, because an older person has fewer expected years left to lose, his WTP to reduce mortality risk would be less than that of a younger person. This hypothesis is supported by one empirical study, Jones-Lee et al.(1985), that found the value of a statistical life at age 65 to be about 90 percent of what it is at age 40. Citing the evidence provided by Jones-Lee et al., Chestnut (1995) assumed that the value of a statistical life for those 65 and over is 75 percent of what it is for those under 65.

The greater risk aversion of older people, however, implies just the opposite. Citing Ehrlich and Chuma (1990), Industrial Economics Inc. (1992) noted that "older persons, who as a group tend to avoid health risks associated with drinking, smoking, and reckless driving, reveal a greater demand for reducing mortality risks and hence have a greater implicit value of a life year." That is, the more risk averse behavior of older individuals suggests a greater WTP to reduce mortality risk.

There is substantial evidence that the income elasticity of WTP for health risk reductions is positive (Loehman and De, 1982; Jones-Lee et al., 1985; Mitchell and Carson, 1986; Gerking et al., 1988; Alberini et al., 1997), although there is uncertainty about the exact value of this elasticity). Individuals with higher incomes (or greater wealth) should, then, be willing to pay more to reduce risk, all else equal, than individuals with lower incomes or wealth. Whether the average income or level of wealth of the population affected by ambient air pollution reductions is likely to be significantly different from that of subjects in wage-risk studies, however, is unclear.

Finally, although there may be several ways in which job-related mortality risks differ from air pollution-related mortality risks, the most important difference may be that job-related risks are incurred voluntarily whereas air pollution-related risks are incurred involuntarily.

There is some evidence that people will pay more to reduce involuntarily incurred risks than risks incurred voluntarily (e.g., Violette and Chestnut, 1983). Job-related risks are incurred voluntarily whereas air pollution-related risks are incurred involuntarily. If this is the case, WTP estimates based on wage-risk studies may be downward biased estimates of WTP to reduce involuntarily incurred ambient air pollution-related mortality risks.

The potential sources of bias in an estimate of MWTP to reduce the risk of air pollution related mortality based on wage-risk studies are summarized in Table 5-5. Although most of the individual factors tend to have a downward bias, the overall effect of these biases is unclear.

Table 5-5 Potential Sources of Bias in Estimates of Mean WTP to Reduce the Risk of PM Related Mortality Based on Wage-Risk Studies

Factor	Likely Direction of Bias in Mean WTP Estimate
Age	Uncertain
Degree of Risk Aversion	Downward
Income	Downward, if the elderly affected are a random sample of the elderly. It is unclear, if the elderly affected are the poor elderly.
Risk Perception: Voluntary vs. Involuntary risk	Downward

Chronic Illness

Researchers have linked air pollution with a variety of adverse health effects that have long-term, or chronic implications. The onset of bronchitis has been associated with exposure to air pollutants. Studies have linked the onset of chronic bronchitis in adults to particulate matter (Schwartz, 1993; Abbey et al., 1995c). These results are consistent with research that has found chronic exposure to pollutants leads to declining pulmonary functioning (Detels et al., 1991; Ackermann-Liebrich et al., 1997; Abbey et al., 1998).

Chronic Bronchitis

Chronic bronchitis is characterized by mucus in the lungs and a persistent wet cough for at least three months a year for several years in a row, and affects roughly five percent of the U.S. population (American Lung Association, 2002b, Table 4). There are a limited number of studies that have estimated the impact of air pollution on new incidences of chronic bronchitis. Schwartz (1993) and Abbey et al.(1995c) provide evidence that long-term PM exposure gives rise to the development of chronic bronchitis in the U.S.

We estimate the changes in the number of new cases of PM-related chronic bronchitis using a study by Abbey et al. (1995c) which is based on a sample of California residents. The study by Abbey et al. (1995c) examined the relationship between estimated $PM_{2.5}$ (annual mean from 1966 to 1977), PM_{10} (annual mean from 1973 to 1977) and TSP (annual mean from 1973 to 1977) and the same chronic respiratory symptoms in a sample population of 1,868 Californian Seventh-Day Adventists. The initial survey was conducted in 1977 and the final survey in 1987. To ensure a better estimate of exposure, the study participants had to have been living in the same area for an extended period of time. In single-pollutant models, there was a statistically significant $PM_{2.5}$ relationship with development of chronic bronchitis, but not for airway obstructive disease (AOD) or asthma; PM_{10} was significantly associated with chronic bronchitis and AOD; and TSP was significantly associated with all cases of all three chronic symptoms. Other pollutants were not examined.

Table 5-6 Chronic Bronchitis Study

Location	Study	Pollutants Used in Final Model	Age of Study Population
California	Abbey et al. (1995c)	$PM_{2.5}$	>26

Valuing Chronic Bronchitis

PM-related chronic bronchitis is expected to last from the initial onset of the illness throughout the rest of the individual's life. WTP to avoid chronic bronchitis would therefore be expected to incorporate the present discounted value of a potentially long stream of costs (e.g., medical expenditures and lost earnings) and pain and suffering associated with the illness. Two studies, Viscusi et al. (1991) and Krupnick and Cropper (1992), provide estimates of WTP to avoid a case of chronic bronchitis.

The Viscusi et al. (1991) and the Krupnick and Cropper (1992) studies were experimental studies intended to examine new methodologies for eliciting values for morbidity endpoints. Although these studies were not specifically designed for policy analysis, we believe the studies provide reasonable estimates of the WTP for chronic bronchitis. As with other contingent valuation studies, the reliability of the WTP estimates depends on the methods used to obtain the WTP values. The Viscusi et al. and the Krupnick and Cropper studies are broadly consistent with current contingent valuation practices, although specific attributes of the studies may not be.

The study by Viscusi et al. uses a sample that is larger and more representative of the general population than the study by Krupnick and Cropper (which selects people who have a relative with the disease). Thus, the valuation for the high-end estimate is based on the distribution of WTP responses from Viscusi et al. The WTP to avoid a case of pollution-related chronic bronchitis (CB) is derived by starting with the WTP to avoid a severe case of chronic bronchitis, as described by Viscusi et al. (1991), and adjusting it downward to reflect (1) the decrease in severity of a case of pollution-related CB relative to the severe case described in the Viscusi et al. study, and (2) the elasticity of WTP with respect to severity reported in the Krupnick and Cropper study. Because elasticity is a marginal concept and because it is a function of severity (as estimated from Krupnick and Cropper, 1992), WTP adjustments were made incrementally, in one percent steps. A severe case of CB was assigned a severity level of 13 (following Krupnick and Cropper). The WTP for a one percent decrease in severity is given by:

$$WTP_{0.99\,sev} = WTP_{sev} \cdot (1 - 0.01 \cdot e) \ ,$$

where sev is the original severity level (which, at the start, is 13) and e is the elasticity of WTP with respect to severity. Based on the regression in Krupnick and Cropper (1992) (see below), the estimate of e is 0.18*sev. At the mean value of sev (6.47), e = 1.16. As severity decreases, however, the elasticity decreases. Using the regression coefficient of 0.18, the above equation can be rewritten as:

$$WTP_{0.99\,sev} = WTP_{sev} \cdot (1 - 0.01 \cdot 0.18 sev) \ .$$

For a given WTP_{sev} and a given coefficient of sev (0.18), the WTP for a 50 percent reduction in severity can be obtained iteratively, starting with sev =13, as follows:

$$WTP_{12.87} = WTP_{0.99 \cdot 13} = WTP_{13} \cdot (1 - 0.01 \cdot 0.18 \cdot 13)$$

$$WTP_{12.74} = WTP_{0.99 \cdot 12.87} = WTP_{12.87} \cdot (1 - 0.01 \cdot 0.18 \cdot 12.87)$$

$$WTP_{12.61} = WTP_{0.99 \cdot 12.74} = WTP_{12.74} \cdot (1 - 0.01 \cdot 0.18 \cdot 12.74)$$

and so forth. This iterative procedure eventually yields $WTP_{6.5}$, or WTP to avoid a case of chronic bronchitis that is of "average" severity.

The derivation of the WTP to avoid a case of pollution-related chronic bronchitis is based on three components, each of which is uncertain: (1) the WTP to avoid a case of severe CB, as described in the Viscusi et al. (1991) study, (2) the severity level of an average pollution-related case of CB (relative to that of the case described by Viscusi et al.), and (3) the elasticity of WTP with respect to severity of the illness. Because of these three sources of uncertainty, the WTP is uncertain. Based on assumptions about the distributions of each of the three uncertain components, a distribution of WTP to avoid a pollution-related case of CB was derived by Monte Carlo methods. The mean of this distribution, which was about $319,000 ($331,000 in 1999$), is taken as the central tendency estimate of WTP to avoid a pollution-related case of CB. Each of the three underlying distributions is described briefly below.

1. The distribution of WTP to avoid a severe case of CB was based on the distribution of WTP responses in the Viscusi et al. (1991) study. Viscusi et al. derived respondents' implicit WTP to avoid a statistical case of chronic bronchitis from their WTP for a specified reduction in risk. The mean response implied a WTP of about $1,275,000 (1999 $)[15]; the median response implied a WTP of about $676,000 (1999

[15] There is an indication in the Viscusi et al. (1991) paper that the dollar values in the paper are in 1987 dollars. Under this assumption, the dollar values were converted to 1999 dollars.

$). However, the extreme tails of distributions of WTP responses are usually considered unreliable. Because the mean is much more sensitive to extreme values, the median of WTP responses is often used rather than the mean. Viscusi et al. report not only the mean and median of their distribution of WTP responses, however, but the decile points as well. The distribution of reliable WTP responses from the Viscusi et al. study could therefore be approximated by a discrete uniform distribution giving a probability of 1/9 to each of the first nine decile points. This omits the first five and the last five percent of the responses (the extreme tails, considered unreliable). This trimmed distribution of WTP responses from the Viscusi et al. study was assumed to be the distribution of WTPs to avoid a severe case of CB. The mean of this distribution is about $918,000 (1999 $).

2. The distribution of the severity level of an average case of pollution-related CB was modeled as a triangular distribution centered at 6.5, with endpoints at 1.0 and 12.0. These severity levels are based on the severity levels used in Krupnick and Cropper (1992), which estimated the relationship between ln(WTP) and severity level, from which the elasticity is derived. The most severe case of CB in that study is assigned a severity level of 13. The mean of the triangular distribution is 6.5. This represents a 50 percent reduction in severity from a severe case.

3. The elasticity of WTP to avoid a case of CB with respect to the severity of that case of CB is a constant times the severity level. This constant was estimated by Krupnick and Cropper (1992) in the regression of ln(WTP) on severity, discussed above. This estimated constant (regression coefficient) is normally distributed with mean = 0.18 and standard deviation = 0.0669 (obtained from Krupnick and Cropper).

The distribution of WTP to avoid a case of pollution-related CB was generated by Monte Carlo methods, drawing from the three distributions described above. On each of 16,000 iterations (1) a value was selected from each distribution, and (2) a value for WTP was generated by the iterative procedure described above, in which the severity level was decreased by one percent on each iteration, and the corresponding WTP was derived. The mean of the resulting distribution of WTP to avoid a case of pollution-related CB was $331,000 (1999$).

This WTP estimate is reasonably consistent with full COI estimates derived for chronic bronchitis, using average annual lost earnings and average annual medical expenditures reported by Cropper and Krupnick (1990) Using a 5 percent discount rate and assuming that (1) lost earnings continue until age 65, (2) medical expenditures are incurred until death, and (3) life expectancy is unchanged by chronic bronchitis, the present discounted value of the stream of medical expenditures and lost earnings associated with an average case of chronic bronchitis is estimated to be about $113,000 for a 30 year old, about $109,000 for a 40 year old, about $100,000 for a 50 year old, and about $57,000 for a 60 year old. A WTP estimate would be expected to be greater than a full COI estimate, reflecting the willingness to pay to avoid the pain and suffering associated with the illness. The WTP estimate of $331,000 is from 2.9 times the full COI estimate (for 30 year olds) to 5.8 times the full COI estimate (for 60 year olds).

Heart Attacks

Non-Fatal Myocardial Infarction (Heart Attacks)

Non-fatal heart attacks have been linked with short term exposures to $PM_{2.5}$ in the U.S. (Peters et al., 2001) and other countries (Poloniecki et al., 1997). We used a recent study by Peters et al. as the basis for the C-R function estimating the relationship between $PM_{2.5}$ and non-fatal heart attacks. It is the only available U.S. study to provide a specific estimate for heart attacks. Other studies, such as Samet et al. (2000) and Moolgavkar et al. (2000a) reported a consistent relationship between all cardiovascular hospital admissions, including for non-fatal heart attacks, and PM. However, they did not focus specifically on heart attacks. Given the lasting impact of a heart attack on longer-term health costs and earnings, we chose to provide a separate estimate for non-fatal heart attacks based on the single available U.S. C-R function.

The finding of a specific impact on heart attacks is consistent with hospital admission and other studies showing relationships between fine particles and cardiovascular effects both within and outside the U.S. These studies provide a weight of evidence for this type of effect. Several epidemiologic studies (Liao et al., 1999; Gold et al., 2000; Magari et al., 2001) have shown that heart rate variability (an indicator of how much the heart is able to speed up or slow down in response to momentary stresses) is negatively related to PM levels. Lack of heart rate variability is a risk factor for heart attacks and other coronary heart diseases (Tsuji et al., 1996; Liao et al., 1997; Dekker et al., 2000). As such, the reduction in heart rate variability due to PM is consistent with an increased risk of heart attacks.

Valuing Non-Fatal Myocardial Infarction (Heart Attack)

EPA has not previously estimated the impact of its programs on reductions in the expected number of non-fatal heart attacks, although it has examined the impact of reductions in other related cardiovascular endpoints. We were not able to identify a suitable WTP value for reductions in the risk of non-fatal heart attacks. Instead, we have used a cost-of-illness unit value with two components: the direct medical costs and the opportunity cost (lost earnings) associated with the illness event. Because the costs associated with a heart attack extend beyond the initial event itself, we considered costs incurred over several years. For opportunity costs, we used values derived from Cropper and Krupnick (1990), originally used in the 812 Retrospective Analysis of the Clean Air Act (U.S. EPA, 1997b). For the direct medical costs, we found three possible sources in the literature.

Wittels et al. (1990) estimated expected total medical costs of myocardial infarction over five years to be $51,211 (in 1986$) for people who were admitted to the hospital and survived hospitalization. (There does not appear to be any discounting used.) Using the CPI-U for medical care, the Wittels et al. estimate is $109,474 in year 2000$. This estimated cost is based on a medical cost model, which incorporated therapeutic options, projected outcomes and prices (using “knowledgeable cardiologists” as consultants). The model used medical data and medical decision algorithms to estimate the probabilities of certain events and/or medical procedures being used. The authors noted that the average length of hospitalization for acute myocardial infarction has decreased over time (from an average of 12.9 days in 1980 to an average of 11 days in 1983). Wittels et al. used 10 days as the average in their study. It is unclear how much further the length of stay may have decreased from 1983 to the present. The average length of stay for ICD code 410 (myocardial infarction) in 2000 is 5.5 days ((AHRQ 2000)). However, this may include patients who died in the hospital (not included among our non-fatal cases), whose length of stay was therefore substantially shorter than it would be if they hadn’t died.

Eisenstein et al. (2001) estimated 10-year costs of $44,663, in 1997$, or $49,651 in 2000$ for myocardial infarction patients, using statistical prediction (regression) models to estimate inpatient costs. Only inpatient costs (physician fees and hospital costs) were included.

Russell et al. (1998) estimated first-year direct medical costs of treating nonfatal myocardial infarction of $15,540 (in 1995$), and $1,051 annually thereafter. Converting to year 2000$, that would be $23,353 for a 5-year period (without discounting), or $29,568 for a ten-year period.

As seen in Table 4-12, the three different studies provided significantly different values. We have not adequately resolved the sources of differences in the estimates. Because the wage-related opportunity cost estimates from Cropper and Krupnick (1990) cover a 5-year period, we used a simple average of the two estimates for medical costs that similarly cover a 5-year period, or $62,495. We added this to the 5-year opportunity cost estimate. Table 4-13 gives the resulting estimates. We currently do not have adequate information to characterize the uncertainty surrounding any of these estimates.

Table 5-7. Summary of Studies Valuing Reduced Incidences of Myocardial Infarction

Study	Direct Medical Costs (2000$) [a]	Over an x-year period, for x =
Wittels et al., 1990	$109,474	5
Russell et al., 1998	$22,331	5
Eisenstein et al., 2001	$49,651	10
Russell et al., 1998	$27,242	10

[a] Wittels et al. did not appear to discount costs incurred in future years. The values for the other two studies are based on a three percent discount rate.

Table 5-8. Estimated Costs Over a 5-Year Period of a Non-Fatal Myocardial Infarction

Age Group	Opportunity Cost [a]		Medical Cost [b]		Total Cost	
	3% Discount Rate	*7% Discount Rate*	*3% Discount Rate*	*7% Discount Rate*	*3% Discount Rate*	*7% Discount Rate*
0 - 24	$0	$0	$65,902	$65,293	$65,902	$65,293
25-44	$8,774	$7,855	$65,902	$65,293	$74,676	$73,149
45 - 54	$12,932	$11,578	$65,902	$65,293	$78,834	$76,871
55 - 65	$74,746	$66,920	$65,902	$65,293	$140,649	$132,214
> 65	$0	$0	$65,902	$65,293	$65,902	$65,293

[a] From Cropper and Krupnick (1990). Present discounted value of 5 yrs of lost earnings, at 3% and 7% discount rate, adjusted from 1977$ to 2000$ using CPI-U "all items".

[b] An average of the 5-year costs estimated by Wittels et al. (1990) and Russell et al. (1998). Note that Wittels et al. appears not to have used discounting in deriving a 5-year cost of $109,474; Russell et al. estimated first-year direct medical costs and annual costs thereafter. The resulting 5-year cost is $22,331, using a 3% discount rate, and $21,113, using a 7% discount rate. Medical costs were inflated to 2000$ using CPI-U for medical care.

Hospital Admissions

We estimate the impact of PM on both respiratory and cardiovascular hospital admissions. In addition, we estimate the impact of these pollutants on emergency room visits for asthma. The respiratory and cardiovascular hospital admissions studies used in the primary analysis are listed in Tables 5-7 and 5-8, respectively. Appendix A provides details on each study. Due to the availability of detailed hospital admission and discharge records, there is an extensive body of literature examining the relationship between hospital admissions and air pollution. Because of this, we pooled some of the hospital admission endpoints, using the results of a number of studies. Although the benefits associated with respiratory and cardiovascular hospital admissions are estimated separately in the analysis, the methods used to estimate changes in incidence and to value those changes are the same for both broad categories of hospital admissions. The two categories of hospital admissions are therefore discussed together in this section.

Table 5-9 Respiratory Hospital Admission Studies

Location	Study	Endpoints Estimated (ICD code)	Pollutants Used in Final Model	Age of Study Population
PM-Related Hospital Admissions				
Los Angeles, CA	Moolgavkar (2000c)	Chronic Lung Disease Less Asthma(ICD codes 490-492, 494-496)	$PM_{2.5}$	Ages 18-64
Seattle, WA	Sheppard et al. (1999)	asthma (493)	$PM_{2.5}$	<65
Detroit, MI	Lippmann et al. (2000)	Pneumonia (ICD-9 codes 480-487)	$PM_{2.5}$	Ages 65+
Detroit, (Lippman) Chicago, Los Angeles, and Phoenix (Moolgavkar)	Lippmann et al. (2000), Moolgavkar (2000b)	Chronic Lung Disease (ICD codes 490-496)	$PM_{2.5}$	Ages 65+
Seattle, WA	Norris et al. (1999)	Asthma-related ER visits (ICD code 493)	$PM_{2.5}$	< 18

Table 5-10 Cardiovascular Hospital Admission Study

Location	Study	Endpoints Estimated (ICD code)	Pollutants Used in Final Model	Age of Study Population
PM-Related Hospital Admissions				
Los Angeles, CA	Moolgavkar (2000a)	Cardiovascular (ICD codes 390-409, 411-429)[16]	$PM_{2.5}$	Ages 20-64
Los Angeles (Moolgavkar), Detroit (Lippman)	Moolgavkar (2000a), Lippmann et al. (2000)	Cardiovascular ((ICD codes 390-409, 411-429)[17]	$PM_{2.5}$	age 65+

PM-Related Respiratory and Cardiovascular Hospital Admissions

To estimate avoided incidences of cardiovascular hospital admissions associated with $PM_{2.5}$, we use studies by Moolgavkar (2000a) and Lippmann et al. (2000). There are additional published studies showing a statistic ally significant relationship between PM_{10} and cardiovascular hospital admissions. However, given that the control option we are analyzing is expected to reduce primarily $PM_{2.5}$, we have chosen to focus on the two studies focusing on $PM_{2.5}$. Both of these studies estimated a C-R function for populations over 65, allowing us to pool the C-R functions for this age group. Only Moolgavkar estimated a separate C-R function for populations 20 to 64. Total cardiovascular hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Cardiovascular hospital admissions include admissions for myocardial infarctions. In order to avoid double counting benefits from reductions in MI when applying the C-R function for cardiovascular hospital admissions, we first adjusted the baseline cardiovascular hospital admissions to remove admissions for myocardial infarction.

To estimate total avoided incidences of respiratory hospital admissions, we use C-R functions for several respiratory causes, including chronic obstructive pulmonary disease (COPD), pneumonia, and asthma. As with cardiovascular admissions, there are additional published studies showing a statistically significant relationship between PM_{10} and respiratory hospital admissions. We use only those focusing on $PM_{2.5}$. Both Moolgavkar (2000a) and Lippmann et al (2000) estimated C-R functions for COPD in populations over 65, allowing us to pool the C-R functions for this group. Only Moolgavkar estimated a separate C-R function for populations 20 to 64. Total COPD hospital admissions are thus the sum of the pooled estimate for populations over 65 and the single study estimate for populations 20 to 64. Only Lippmann et al estimated pneumonia,

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[16] Moolgavkar (2000a) reports results that include ICD code 410 (heart attack). In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

[17] Moolgavkar (2000a) reports results for ICD codes 390-429. In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

and only for the population 65 and older. In addition, Sheppard et al (1999) estimated a C-R function for asthma hospital admissions for populations under age 65. Total avoided incidences of PM-related respiratory-related hospital admissions is the sum of COPD, pneumonia, and asthma admissions.

Valuing Respiratory and Cardiovascular Hospital Admissions

Society's WTP to avoid a hospital admission includes medical expenses, lost work productivity, the non-market costs of treating illness (i.e., air, water and solid waste pollution from hospitals and the pharmaceutical industry), and the pain and suffering of the affected individual as well as of that of relatives, friends, and associated caregivers.[18]

Because medical expenditures are to a significant extent shared by society, via medical insurance, Medicare, etc., the medical expenditures actually incurred by the individual are likely to be less than the total medical cost to society. The total value to society of an individual's avoidance of hospital admission, then, might be thought of as having two components: (1) the cost of illness (COI) to society, including the total medical costs plus the value of the lost productivity, as well as (2) the WTP of the individual, as well as that of others, to avoid the pain and suffering resulting from the illness.

In the absence of estimates of social WTP to avoid hospital admissions for specific illnesses (components 1 plus 2 above), estimates of total COI (component 1) are typically used as conservative (lower bound) estimates. Because these estimates do not include the value of avoiding the pain and suffering resulting from the illness (component 2), they are biased downward. Some analyses adjust COI estimates upward by multiplying by an estimate of the ratio of WTP to COI, to better approximate total WTP. Other analyses have avoided making this adjustment because of the possibility of over-adjusting -- that is, possibly replacing a known downward bias with an upward bias. The COI values used in this benefits analysis will not be adjusted to better reflect the total WTP.

Following the method used in the §812 analysis (U.S. EPA, 1999b), ICD-code-specific COI estimates used in our analysis consist of two components: estimated hospital charges and the estimated opportunity cost of time spent in the hospital (based on the average length of a hospital stay for the illness). The opportunity cost of a day spent in the hospital is estimated as the value of the lost daily wage, regardless of whether or not the individual is in the workforce. This is estimated at $106 (U.S. Bureau of the Census, 1992).

For all hospital admissions included in this analysis, estimates of hospital charges and lengths of hospital stays were based on discharge statistics provided by Elixhauser et al. (1993). The total COI for an ICD-code-specific hospital stay lasting n days, then, would be estimated as the mean hospital charge plus $106*n. Most respiratory hospital admissions categories considered in epidemiological studies consisted of

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[18] Some people take action to avert the negative impacts of pollution. While the costs of successful averting behavior should be added to the sum of the health-endpoint-specific costs when estimating the total costs of pollution, these costs are not associated with any single health endpoint It is possible that in some cases the averting action was not successful, in which case it might be argued that the cost of the averting behavior should be added to the other costs listed (for example, it might be the case that an individual incurs the costs of averting behavior and in addition incurs the costs of the illness that the averting behavior was intended to avoid). Because averting behavior is generally not taken to avoid a particular health problem (such as a hospital admission for respiratory illness), but instead is taken to avoid the entire collection of adverse effects of pollution, it does not seem reasonable to ascribe the entire costs of averting behavior to any single health endpoint.

sets of ICD codes. The unit dollar value for the set of ICD codes was estimated as the weighted average of the ICD-code-specific mean hospital charges of each ICD code in the set. The weights were the relative frequencies of the ICD codes among hospital discharges in the United States, as estimated by the National Hospital Discharge Survey [Owings, 1999 #1872]. The study-specific values for valuing respiratory and cardiovascular hospital admissions are shown in Tables 5-9 and 5-10, respectively.

The mean hospital charges and mean lengths of stay provided by Elixhauser et al. (1993) are based on a very large nationally representative sample of about seven million hospital discharges, and are therefore the best estimates of mean hospital charges and mean lengths of stay available, with negligible standard errors. However, because of distortions in the market for medical services, the hospital charge may exceed “the cost of a hospital stay.” We use the example of a hospital visit to illustrate the problem. Suppose a patient is admitted to the hospital to be treated for an asthma episode. The patient’s stay in the hospital (including the treatments received) costs the hospital a certain amount. This is the hospital cost – i.e., the short-term expenditures of the hospital to provide the medical services that were provided to the patient during his hospital stay. The hospital then charges the payer a certain amount – the hospital charge. If the hospital wants to make a profit, is trying to cover costs that are not associated with any one particular patient admission (e.g., uninsured patient services), and/or has capital expenses (building expansion or renovation) or other long term costs, it may charge an amount that exceeds the patient-specific short term costs of providing services. The payer (e.g., the health maintenance organization or other health insurer) pays the hospital a certain amount – the payment – for the services provided to the patient. The less incentive the payer has to keep costs down, the closer the payment will be to the charge. If, however, the payer has an incentive to keep costs down, the payment may be substantially less than the charge; it may still, however, exceed the short-term cost for services to the individual patient.

Although the hospital charge may exceed the short-term cost to the hospital of providing the medical services required during a patient’s hospital stay, cost of illness estimates based on hospital charges are still likely to understate the total social WTP to avoid the hospitalization in the first place, because the omitted WTP to avoid the pain and suffering is likely to be quite large.

Table 5-11 Unit Values for Respiratory Hospital Admissions*

Location	Study	Endpoints Estimated (ICD code)	Age of Study Population	COI [a] (1999 $)
PM-Related Hospital Admissions				
Los Angeles, CA	Moolgavkar (2000c)	Chronic Lung Disease Less Asthma(ICD codes 490-492, 494-496)	Ages 18-64	$11,333
Seattle, WA	Sheppard et al. (1999)	Asthma (493)	<65	$7,467
Detroit, MI	Lippmann et al. (2000)	Pneumonia (ICD-9 codes 480-487)	Ages 65+	$17,106
Detroit (Lippman) Chicago, Los Angeles, and Phoenix (Moolgavkar)	Lippmann et al. (2000), Moolgavkar (2000b)	Chronic Lung Disease (ICD codes 490-496)	Ages 65+	$13,083

Location	Study	Endpoints Estimated (ICD code)	Age of Study Population	COI [a] (1999 $)
Seattle, WA	Norris et al. (1999)	Asthma-related ER visits (ICD code 493)	< 18	$275

[a] The unit value for a group of ICD-9 codes is the weighted average of ICD-9 code-specific values, from Elixhauser et al. (1993). The weights are the relative frequencies of hospital discharges in Elixhauser et al. for each ICD-9 code in the group. The monetized benefits of non-overlapping endpoints within each study were aggregated. Monetized benefits for asthma among people age <65 (Sheppard et al., 1999) were aggregated with the monetized benefits in Samet et al. (2000) of people age >64.

Table 5-12 Unit Values for Cardiovascular Hospital Admissions*

Location	Study	Endpoints Estimated (ICD code)	Age of Study Population	COI [a] (1999 $)
PM-Related Hospital Admissions				
Los Angeles, CA	Moolgavkar (2000a)	Cardiovascular (ICD codes 390-409, 411-429)[19]	Ages 20-64	$21,864(ICD codes 390-429)
Los Angeles (Moolgavkar), Detroit (Lippman)	Moolgavkar (2000a), Lippmann et al. (2000)	Cardiovascular ((ICD codes 390-409, 411-429)[20]	age 65+	$20,334(ICD codes 390-429)

[*] The unit value for a group of ICD-9 codes is the weighted average of ICD-9 code-specific values, from Elixhauser et al. (1993). The weights are the relative frequencies of hospital discharges in Elixhauser et al. for each ICD-9 code in the group.

We were not able to estimate the uncertainty surrounding cost-of-illness estimates for hospital admissions because 1993 was the last year for which standard errors of estimates of mean hospital charges were reported . However, the standard errors reported in 1993 were very small because estimates of mean hospital charges were based on large sample sizes, and the overall sample size in 1997 was about ten times as large as that in 1993 (at about seven million hospital discharges in all). The standard errors of the current estimates of mean hospital charges will therefore be negligible. Therefore, although we cannot include the uncertainty surrounding these cost-of-illness estimates in our overall uncertainty analysis, the omission of this component of uncertainty will have virtually no impact on the overall characterization of uncertainty.

Asthma-Related Emergency Room (ER) Visits

To estimate the effects of PM air pollution reductions on asthma-related ER visits, we use the C-R function based on a study of children 18 and under by Norris et al. (1999). As noted earlier, there is another study by Schwartz examining a broader age group (less than 65), but the Schwartz study focused on PM_{10} rather than $PM_{2.5}$. We selected the Norris et al. C-R function because it better matched the pollutant of interest. Because children tend to have higher rates of hospitalization for asthma relative to adults under 65, we will likely capture the majority of the impact of $PM_{2.5}$ on asthma ER visits in populations under 65, although there may still be significant impacts in the adult population under 65.

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[19] Moolgavkar (2000a) reports results that include ICD code 410 (heart attack). In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

[20] Moolgavkar (2000a) reports results for ICD codes 390-429. In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

Initially we were concerned about double-counting the benefits from reducing both hospital admissions and ER visits. However, our estimates of hospital admission costs do not include the costs of admission to the ER, so we can safely estimate both hospital admissions and ER visits.

Valuing Asthma-Related Emergency Room (ER) Visits

The value of an avoided asthma-related ER visit was based on national data reported in Smith et al. (1997). Smith et al. reported that there were approximately 1.2 million asthma-related ER visits made in 1987, at a total cost of $186.5 million, in 1987$. The average cost per visit was therefore $155 in 1987$, or $298.62 in 1999 $ (using the CPI-U for medical care to adjust to 1999 $). The uncertainty surrounding this estimate, based on the uncertainty surrounding the number of ER visits and the total cost of all visits reported by Smith et al. was characterized by a triangular distribution centered at $298.62, on the interval [$221.65, $414.07].

A second unit value is $249.86($1999) from Stanford et al. (1999). This study considered asthmatics in 1996-1997, in comparison to the Smith et al. (1997) study, which used 1987 National Medical Expenditure Survey (NMES) data). In comparing their study, the authors note that the 1987 NMES, used by Smith et al., "may not reflect changes in treatment patterns during the 1990s." In addition, its costs are the costs to the hospital (or ER) for treating asthma rather than charges or payments by the patient and/or third party payer. Costs to the ER are probably a better measure of the value of the medical resources used up on an asthma ER visit (see above for a discussion of costs versus charges). An average of these two values gives an estimate of $275($1999) for an Asthma-Related ER visits.

Acute Illnesses and Symptoms Not Requiring Hospitalization

We consider in this section a number of acute symptoms that do not require hospitalization, such as acute bronchitis, and upper and lower respiratory symptoms. Several of these illnesses and symptoms were considered in the §812 Prospective analysis as well. The unit values and the uncertainty distributions for those acute illnesses and symptoms that were also considered in the §812 Prospective analysis were obtained by adjusting the unit values used in that analysis from 1990 $ to 1999 $ by multiplying by 1.275 (based on the CPI-U for "all items").

Table 5-13 Studies of Symptoms/Illnesses not Requiring Hospitalization

Endpoint	Study	Pollutants	Study Population
Acute bronchitis	Dockery et al. (1996)	$PM_{2.5}$	Ages 8-12
Upper respiratory symptoms (URS)	Pope et al. (1991)	PM_{10}	Asthmatics, ages 9-11
Lower respiratory symptoms (LRS)	Schwartz et al. (1994)	$PM_{2.5}$	Ages 7-14
Minor restricted activity day (MRAD)	Ostro and Rothschild (1989),	$PM_{2.5}$	Ages 18-65
Work loss days (WLDs)	Ostro (1987)	$PM_{2.5}$	Ages 18-65

Acute Bronchitis

Around five percent of U.S. children between ages five and seventeen experience episodes of acute bronchitis annually (Adams and Marano, 1995). Acute bronchitis is characterized by coughing, chest discomfort, slight fever, and extreme tiredness, lasting for a number of days. According to the MedlinePlus medical encyclopedia[21], with the exception of cough, most acute bronchitis symptoms abate within 7 to 10 days. We estimated the incidence of episodes of acute bronchitis in children between the ages 8-12 using a C-R function developed from Dockery et al. (1996).

Dockery et al. (1996) examined the relationship between PM and other pollutants on the reported rates of asthma, persistent wheeze, chronic cough, and bronchitis, in a study of 13,369 children ages 8-12 living in 24 communities in the U.S. and Canada. Health data were collected in 1988-1991, and single-pollutant models were used in the analysis to test a number of measures of particulate air pollution. Dockery et al. found that annual level of sulfates and particle acidity were significantly related to bronchitis, and $PM_{2.5}$ and PM_{10} were marginally significantly related to bronchitis.

Valuing Acute Bronchitis

Estimating WTP to avoid a case of acute bronchitis is difficult for several reasons. First, WTP to avoid acute bronchitis itself has not been estimated. Estimation of WTP to avoid this health endpoint therefore must be based on estimates of WTP to avoid symptoms that occur with this illness. Second, a case of acute bronchitis may last more than one day, whereas it is a day of avoided symptoms that is typically valued. Finally, the C-R function used in the benefit analysis for acute bronchitis was estimated for children, whereas WTP estimates for those symptoms associated with acute bronchitis were obtained from adults.

Three unit values are available in BenMAP for acute bronchitis in children. In previous benefits analyses, EPA used a unit value of $57.38. This is the midpoint between a low estimate and a high estimate. The low estimate is the sum of the midrange values recommended by IEc (1994) for two symptoms believed to be associated with acute bronchitis: coughing and chest tightness. The high estimate was taken to be twice the value of a minor respiratory restricted activity day.

The above unit value assumes that an episode of acute bronchitis lasts only one day. However, this is generally not the case. More typically, it can last for 6 or 7 days. A simple adjustment, then, would be to multiply the original unit value of $57.38 by 6 or 7. A second unit value of $344 (=$57.38 x 6) was therefore derived.

Finally, as noted above, the epidemiological study relating air pollution to the incidence of acute bronchitis referred to children specifically. The value of an avoided case should therefore be WTP to avoid a case in a child, which may be different from WTP to avoid a case in an adult. Recent work by Dickie and Ulery (2002) suggests, in fact, that parents are generally willing to pay about twice as much to avoid sickness in their children as in themselves.[22] In one of several models they estimated, the natural logarithm of parents' WTP was related both to the number of symptom-days avoided and to whether it was their child or themselves at issue. Dickie and Ulery noted that "experiencing all of the symptoms [considered in their study

[21] See http://www.nlm.nih.gov/medlineplus/ency/article/000124.htm, accessed January 2002

[22] This is, to our knowledge, the only estimate, based on empirical data, of parental WTP for their children versus themselves.

– cough and phlegm, shortness of breath/wheezing, chest pain, and fever] for 7 days, or 28 symptom-days altogether, is roughly equivalent to a case of acute bronchitis ...” Using this model, and assuming that a case of acute bronchitis can be reasonably modeled as consisting of 28 symptom-days, we estimated parents’ WTP to avoid a case of acute bronchitis in a child to be $358($1999).[23]

Upper Respiratory Symptoms (URS)

Using logistic regression, Pope et al. (1991) estimated the impact of PM_{10} on the incidence of a variety of minor symptoms in 55 subjects (34 “school-based” and 21 “patient-based”) living in the Utah Valley from December 1989 through March 1990. The children in the Pope et al. study were asked to record respiratory symptoms in a daily diary, and the daily occurrences of URS and LRS, as defined above, were related to daily PM_{10} concentrations. Pope et al. describe URS as consisting of one or more of the following symptoms: runny or stuffy nose; wet cough; and burning, aching, or red eyes. Levels of ozone, NO_2, and SO_2 were reported low during this period, and were not included in the analysis.

The sample in this study is relatively small and is most representative of the asthmatic population, rather than the general population. The school-based subjects (ranging in age from 9 to 11) were chosen based on “a positive response to one or more of three questions: ever wheezed without a cold, wheezed for 3 days or more out of the week for a month or longer, and/or had a doctor say the ‘child has asthma’ (Pope et al., 1991, p. 669).” The patient-based subjects (ranging in age from 8 to 72) were receiving treatment for asthma and were referred by local physicians. Regression results for the school-based sample (Pope et al., 1991, Table 5) show PM_{10} significantly associated with both upper and lower respiratory symptoms. The patient-based sample did not find a significant PM_{10} effect. The results from the school-based sample are used here.

Valuing URS

Willingness to pay to avoid a day of URS is based on symptom-specific WTPs to avoid those symptoms identified by Pope et al. as part of the URS complex of symptoms. Three contingent valuation (CV) studies have estimated WTP to avoid various morbidity symptoms that are either within the URS symptom complex defined by Pope et al. (1991) or are similar to those symptoms identified by Pope et al. In each CV study, participants were asked their WTP to avoid a day of each of several symptoms. The WTP estimates corresponding to the morbidity symptoms valued in each study are presented in Table 5-12. The three individual symptoms listed in Table 5-12 that were identified as most closely matching those listed by Pope, et al. for URS are cough, head/sinus congestion, and eye irritation, corresponding to “wet cough,” “runny or stuffy nose,” and “burning, aching or red eyes,” respectively. A day of URS could consist of any one of the seven possible “symptom complexes” consisting of at least one of these three symptoms. Using the symptom symbols in Table 5-12, these seven possible symptom complexes are presented in Table 5-13. It is assumed that each of these seven URS complexes is equally likely.[24] The point estimate of MWTP to

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[23] The mean household income among participants in the Dickie and Ulery CV survey was slightly higher than the national average. We therefore adjusted all WTP estimates that resulted from their models downward slightly, using an income elasticity of WTP of 0.147, the average of the income elasticities estimated in the four models in the study. The adjustment factor thus derived was 0.9738.

[24] With empirical evidence, we could presumably improve the accuracy of the probabilities of occurrence of each type of URS. Lacking empirical evidence, however, a uniform distribution seems the

avoid an occurrence of URS is just an average of the seven estimates of MWTP for the different URS complexes – $18.70, or about $19 in 1990 $. This is $24.23 (=$19*1.275) in 1999 $. In the absence of information surrounding the frequency with which each of the seven types of URS occurs within the URS symptom complex, an uncertainty analysis for WTP to avoid a day of URS is based on a continuous uniform distribution of MWTPs in Table 5-13, with a range of [$7, $33], or [$8.93, $42.08] in 1999 $.

Table 5-14 Median WTP Estimates and Derived Midrange Estimates (in 1999 $)

Symptom [a]	Dickie et al. (1987)	Tolley et al. (1986)	Loehman et al. (1979)	Mid-Range Estimate
Throat congestion	4.81	20.84	-	12.75
Head/sinus congestion	5.61	22.45	10.45	12.75
Coughing	1.61	17.65	6.35	8.93
Eye irritation	-	20.03	-	20.03
Headache	1.61	32.07	-	12.75
Shortness of breath	0.00	-	13.47	6.37
Pain upon deep inhalation (PDI)	5.63	-	-	5.63
Wheeze	3.21	-	-	3.21
Coughing up phlegm	3.51 [b]	-	-	3.51
Chest tightness	8.03	-	-	8.03

[a] All estimates are WTP to avoid one day of symptom. Midrange estimates were derived by IEc (1993).

[b] 10% trimmed mean.

most reasonable “default” assumption.

Table 5-15 Estimates of MWTP to Avoid Upper Respiratory Symptoms (1999 $)

Symptom Combinations Identified as URS by Pope et al. (1991)	MWTP to Avoid Symptom(s)
Coughing	$8.93
Head/Sinus Congestion	$12.75
Eye Irritation	$20.03
Coughing, Head/Sinus Congestion	$21.67
Coughing, Eye Irritation	$28.96
Head/Sinus Congestion, Eye Irritation	$32.78
Coughing, Head/Sinus Congestion, Eye Irritation	$41.71
	Average: $23.83

Based on values reported in Table 5-12.

It is worth emphasizing that what is being valued here is URS *as defined by Pope et al. (1991)*. While other definitions of URS are certainly possible, this definition of URS is used in this benefit analysis because it is the incidence of this specific definition of URS that has been related to PM exposure by Pope et al.

Lower Respiratory Symptoms (LRS)

Lower respiratory symptoms include symptoms such as cough, chest pain, phlegm, and wheeze. To estimate the link between $PM_{2.5}$ and lower respiratory symptoms, we used a study by Schwartz et al. (1994). Schwartz et al. (1994) used logistic regression to link lower respiratory symptoms in children with SO_2, NO_2, ozone, PM_{10}, $PM_{2.5}$, sulfate and H^+ (hydrogen ion). Children were selected for the study if they were exposed to indoor sources of air pollution: gas stoves and parental smoking. The study enrolled 1,844 children into a year-long study conducted in different years (1984 to 1988) in six cities. The students were in grades two through five at the time of enrollment in 1984. By the completion of the final study, the cohort would then be in the eighth grade (ages 13-14); this suggests an age range of 7 to 14.

In single pollutant models SO_2, NO_2, $PM_{2.5}$, and PM_{10} were significantly linked to cough. In two-pollutant models, PM_{10} had the most consistent relationship with cough; ozone was marginally significant, controlling for PM_{10}. In models for upper respiratory symptoms, they reported a marginally significant association for PM_{10}. In models for lower respiratory symptoms, they reported significant single-pollutant models, using SO_2, O_3, $PM_{2.5}$, PM_{10}, SO_4, and H^+. The $PM_{2.5}$ C-R function is based on the single pollutant model reported in Schwartz et al. (1994, Table 5).

Valuing LRS

The method for deriving a point estimate of mean WTP to avoid a day of LRS is the same as for URS. Schwartz et al. (1994, p. 1235) define LRS as at least two of the following symptoms: cough, chest pain, phlegm, and wheeze. The symptoms for which WTP estimates are available that reasonably match those listed by Schwartz et al. for LRS are cough (C), chest tightness (CT), coughing up phlegm (CP), and wheeze (W). A day of LRS, as defined by Schwartz et al., could consist of any one of the 11 combinations of at least two of these four symptoms, as displayed in Table 5-14.[25]

Table 5-14 Estimates of MWTP to Avoid Lower Respiratory Symptoms (1999 $)

Symptom Combinations Identified as LRS by Schwartz et al. (1994)	MWTP to Avoid Symptom(s)
Coughing, Chest Tightness	$16.95
Coughing, Coughing Up Phlegm	$12.42
Coughing, Wheeze	$12.13
Chest Tightness, Coughing Up Phlegm	$11.53
Chest Tightness, Wheeze	$11.24
Coughing Up Phlegm, Wheeze	$6.72
Coughing, Chest Tightness, Coughing Up Phlegm	$20.46
Coughing, Chest Tightness, Wheeze	$20.17
Coughing, Coughing Up Phlegm, Wheeze	$15.64
Chest Tightness, Coughing Up Phlegm, Wheeze	$14.75
Coughing, Chest Tightness, Coughing Up Phlegm, Wheeze	$23.67
	Average: $15.07

Based on values reported in Table 5-12.

We assumed that each of the eleven types of LRS is equally likely.[26] The mean WTP to avoid a day of LRS as defined by Schwartz et al. (1994) is therefore the average of the mean WTPs to avoid each type of LRS, – $11.82. This is $15.07 (=1.275*$11.82) in 1999 $. This is the point estimate used in the benefit analysis for the dollar value for LRS as defined by Schwartz et al. The WTP estimates are based on studies which considered the value of a *day* of avoided symptoms, whereas the Schwartz et al. study used as its

[25] Because cough is a symptom in some of the URS clusters as well as some of the LRS clusters, there is the possibility of a very small amount of double counting – if the same individual were to have an occurrence of URS which included cough and an occurrence of LRS which included cough *both on exactly the same day*. Because this is probably a very small probability occurrence, the degree of double counting is likely to be very minor. Moreover, because URS is applied only to asthmatics ages 9-11 (a very small population), the amount of potential double counting should be truly negligible.

[26] As with URS, if we had empirical evidence we could improve the accuracy of the probabilities of occurrence of each type of LRS. Lacking empirical evidence, however, a uniform distribution seems the most reasonable "default" assumption.

measure a *case* of LRS. Because a case of LRS usually lasts at least one day, and often more, WTP to avoid a day of LRS should be a conservative estimate of WTP to avoid a case of LRS.

In the absence of information about the frequency of each of the seven types of LRS among all occurrences of LRS, the uncertainty analysis for WTP to avoid a day of URS is based on a continuous uniform distribution of MWTPs in Table 5-12, with a range of [$5, $19], or [$6.37, $24.22] in 1999 $. This is the same procedure as that used in the URS uncertainty analysis.

As with URS, it is worth emphasizing that what is being valued here is LRS *as defined by Schwartz et al. (1994)*. While other definitions of LRS are certainly possible, this definition of LRS is used in this benefit analysis because it is the incidence of this specific definition of LRS that has been related to PM exposure by Schwartz et al.

Issues in the Valuation of URS and LRS

The point estimates derived for mean WTP to avoid a day of URS and a case of LRS are based on the assumption that WTPs are additive. For example, if WTP to avoid a day of cough is $8.93, and WTP to avoid a day of shortness of breath is $6.37, then WTP to avoid a day of both cough and shortness of breath is $15.30. If there are no synergistic effects among symptoms, then it is likely that the marginal utility of avoiding symptoms decreases with the number of symptoms being avoided. If this is the case, adding WTPs would tend to overestimate WTP for avoidance of multiple symptoms. However, there may be synergistic effects– that is, the discomfort from two or more simultaneous symptoms may exceed the sum of the discomforts associated with each of the individual symptoms. If this is the case, adding WTPs would tend to underestimate WTP for avoidance of multiple symptoms. It is also possible that people may experience additional symptoms for which WTPs are not available, again leading to an underestimate of the correct WTP. However, for small numbers of symptoms, the assumption of additivity of WTPs is unlikely to result in substantive bias.

There are also three sources of uncertainty in the valuation of both URS and LRS: (1) an occurrence of URS or of LRS may be comprised of one or more of a variety of symptoms (i.e., URS and LRS are each potentially a "complex of symptoms"), so that what is being valued may vary from one occurrence to another; (2) for a given symptom, there is uncertainty about the mean WTP to avoid the symptom; and (3) the WTP to avoid an occurrence of multiple symptoms may be greater or less than the sum of the WTPs to avoid the individual symptoms.

Information about the degree of uncertainty from either the second or the third source is not available. The first source of uncertainty, however, is addressed because an occurrence of URS or LRS may vary in symptoms. For example, seven different symptom complexes that qualify as URS, as defined by Pope et al. (1991), were identified above. The estimates of MWTP to avoid these seven different kinds of URS range from $8.93 (to avoid an occurrence of URS that consists of only coughing) to $42.06 (to avoid an occurrence of URS that consists of coughing plus head/sinus congestion plus eye irritation). There is no information, however, about the frequency of each of the seven types of URS among all occurrences of URS.

Because of insufficient information to adequately estimate the distributions of the estimators of MWTP for URS and LRS, as a rough approximation, a continuous uniform distribution over the interval from the smallest point estimate to the largest is used. As was mentioned in the two previous sections, the interval for URS is [$8.93, $42.06], and for LRS, the interval is [$6.37, $24.22].

Alternatively, a discrete distribution of the seven unit dollar values associated with each of the seven types of URS identified could be used. This would provide a distribution whose mean is the same as the point estimate of MWTP. A continuous uniform distribution, however, is probably more reasonable than a discrete uniform distribution. The differences between the means of the discrete uniform distributions (the point estimates) and the means of the continuous uniform distributions are relatively small, as shown in Table 5-15.

Table 5-16 Comparison of the Means of Discrete and Continuous Uniform Distributions of MWTP Associated with URS and LRS (1990 $)

Health Endpoint	Mean of Discrete Uniform Distribution (Point Est.)	Mean of Continuous Uniform Distribution
URS (Pope et al., 1991)	18.70	19.86
LRS (Schwartz et al., 1994)	11.82	11.92

Minor Restricted Activity Days (MRADs)

Ostro and Rothschild (1989) estimated the impact of $PM_{2.5}$ on the incidence of minor restricted activity days (MRAD) in a national sample of the adult working population, ages 18 to 65, living in metropolitan areas. We developed separate coefficients for each year in the analysis (1976-1981), which were then combined for use in this analysis. The coefficient used in the C-R function is a weighted average of the coefficients in Ostro (Ostro, 1987, Table IV) using the inverse of the variance as the weight.

Valuing Minor Restricted Activity Days (MRADs)

The unit value and uncertainty distribution for MRADs for this analysis were obtained by adjusting the (rounded) values in 1990 $ used in the §812 Prospective analysis to 1999 $ by multiplying by 1.275. No studies are reported to have estimated WTP to avoid a minor restricted activity day (MRAD). However, IEc (1993) has derived an estimate of WTP to avoid a minor respiratory restricted activity day (MRRAD), using WTP estimates from Tolley et al. (1986) for avoiding a three-symptom combination of coughing, throat congestion, and sinusitis. This estimate of WTP to avoid a MRRAD, so defined, is $38.37 (1990 $), or about $38. Although Ostro and Rothschild (1989) estimated the relationship between $PM_{2.5}$ and MRADs, rather than MRRADs (a component of MRADs), it is likely that most of the MRADs associated with exposure to $PM_{2.5}$ are in fact MRRADs. For the purpose of valuing this health endpoint, then, we assumed that MRADs associated with PM exposure may be more specifically defined as MRRADs, and therefore used the estimate of mean WTP to avoid a MRRAD.

Any estimate of mean WTP to avoid a MRRAD (or any other type of restricted activity day other than WLD) will be somewhat arbitrary because the endpoint itself is not precisely defined. Many different combinations of symptoms could presumably result in some minor or less minor restriction in activity. Krupnick and Kopp (1988) argued that mild symptoms will not be sufficient to result in a MRRAD, so that WTP to avoid a MRRAD should exceed WTP to avoid any single mild symptom. A single severe symptom or a combination of symptoms could, however, be sufficient to restrict activity. Therefore WTP to avoid a MRRAD should, these authors argue, not necessarily exceed WTP to avoid a single severe symptom or a combination of symptoms. The "severity" of a symptom, however, is similarly not precisely defined;

moreover, one level of severity of a symptom could induce restriction of activity for one individual while not doing so for another. The same is true for any particular combination of symptoms.

Given that there is inherently a substantial degree of arbitrariness in any point estimate of WTP to avoid a MRRAD (or other kinds of restricted activity days), the reasonable bounds on such an estimate must be considered. By definition, a MRRAD does not result in loss of work. WTP to avoid a MRRAD should therefore be less than WTP to avoid a WLD. At the other extreme, WTP to avoid a MRRAD should exceed WTP to avoid a single mild symptom. The highest IEc midrange estimate of WTP to avoid a single symptom is $15.72 (1990 $), or about $16, for eye irritation. The point estimate of WTP to avoid a WLD in the benefit analysis is $83 (1990 $). If all the single symptoms evaluated by the studies are not severe, then the estimate of WTP to avoid a MRRAD should be somewhere between $16 and $83. Because the IEc estimate of $38 falls within this range (and acknowledging the degree of arbitrariness associated with any estimate within this range), the IEc estimate is used as the mean of a triangular distribution centered at $38, ranging from $16 to $61. Adjusting to 1999 $, this is a triangular distribution centered at $48.43, ranging from $20.34 to $77.76.

Work Loss Days (WLD)

Ostro (1987) estimated the impact of $PM_{2.5}$ on the incidence of work-loss days (WLDs), restricted activity days (RADs), and respiratory-related RADs (RRADs) in a national sample of the adult working population, ages 18 to 65, living in metropolitan areas. The annual national survey results used in this analysis were conducted in 1976-1981. Ostro reported that two-week average $PM_{2.5}$ levels were significantly linked to work-loss days, RADs, and RRADs, however there was some year-to-year variability in the results. Separate coefficients were developed for each year in the analysis (1976-1981); these coefficients were pooled. The coefficient used in the concentration-response function used here is a weighted average of the coefficients in Ostro (1987, Table III) using the inverse of the variance as the weight.

Valuing WLD

Willingness to pay to avoid the loss of one day of work was estimated by dividing the median weekly wage for 1990 (U.S. Bureau of the Census, 1992) by five (to get the median daily wage). This values the loss of a day of work at the national median wage for the day lost. To account for regional variations in median wages, the national daily median wage was adjusted on a county-by-county basis using a factor based on the ratio of national median household income divided by each county's median income. Each county's income-adjusted willingness to pay to avoid the loss of one day of work was then used to value the number of work loss days attributed to that county. Valuing the loss of a day's work at the wages lost is consistent with economic theory, which assumes that an individual is paid exactly the value of his labor.

The use of the median rather than the mean, however, requires some comment. If all individuals in society were equally likely to be affected by air pollution to the extent that they lose a day of work because of it, then the appropriate measure of the value of a work loss day would be the mean daily wage. It is highly likely, however, that the loss of work days due to pollution exposure does not occur with equal probability among all individuals, but instead is more likely to occur among lower income individuals than among high income individuals. It is probable, for example, that individuals who are vulnerable enough to the negative effects of air pollution to lose a day of work as a result of exposure tend to be those with generally poorer health care. Individuals with poorer health care have, on average, lower incomes. To estimate the average lost wages of individuals who lose a day of work because of exposure to PM pollution, then, would require a weighted average of all daily wages, with higher weights on the low end of the wage scale and lower weights on the high end of the wage scale. Because the appropriate weights are not known, however, the median wage was used rather than the mean wage. The median is more likely to approximate the correct value than the mean because means are highly susceptible to the influence of large values in the tail of a distribution (in this case, the small percentage of very large incomes in the United States), whereas the median is not susceptible to these large values. The median daily wage in 1990 was $83, or $105.8 in 1999$. This is the value used to represent work loss days (WLD). An uncertainty distribution for this endpoint was unavailable, therefore the same central estimate ($105.8) was used to value incidence changes at the fifth, mean, and ninety-fifth percentiles.

6 Results

This chapter provides estimates of the magnitude and value of changes in adverse health effects associated with each of the different policy scenarios we considered.

Tables 6-1 through 6-2 present the estimated number of avoidable health effects for each endpoint in each policy option. Tables 6.1 presents the results for 2010 (including the No-EGU analysis, which shows the number of attributable cases of health effects rather than avoidable health effects), and Table 6.2 presents the similar table for 2020. Tables 6-3 and 6-4 present the monetary value of the avoidable health effects for 2010 and 2020, respectively.

Additional details of the results shown in Tables 6-1 through 6.4 are included in Appendix B. The Tables in Appendix B provide uncertainty ranges (5th and 95th percentile values) of the health and valuation estimates.

The estimates of premature mortality included in this report are all based on estimates of the risk of dying attributable to the estimated PM levels in each policy option. As described in Chapter 5, these attributable risks from the estimated annual PM levels for each scenario are estimated in each location. The estimated mortal risk involve not only the changes in PM concentrations, but also data on the age-specific mortality rates in each location. Exhibits 6-1 through 6-10 are maps depicting the estimated mortality rates per 100,000 population from $PM_{2.5}$ from electricity generating units associated with each scenario. In addition to the risks from $PM_{2.5}$ from electricity generating units, there is additional risk from $PM_{2.5}$ coming from other sources. This additional, non-EGU risk is not shown on Exhibits 6-1 to 6-10.

As discussed in Chapter 5, additional epidemiology-based health research has been published since the time the health effects were selected for inclusion in EPA's Clear Skies Analysis. One such important new research paper is the Pope et al., 2002, paper. This research extends previously published results based on the American Cancer Society cohort tracking data.. The primary premature mortality estimates included in the EPA Clear Skies Analysis and in this paper are based earlier results from the ACS cohort data (Krewski et al., 2000). Along with using additional years of follow-on data than was previously available, Pope et al., 2002 also found a statistically significant relationship between $PM_{2.5}$ levels and a specific cause of death: lung cancer.

The EPA Clear Skies Analysis did not include estimates of deaths from lung cancer, so they are not included in the primary result set in this paper. It is possible, however, to use the lung cancer/PM relationship from the Pope et al., 2002 paper to estimate the numbers of avoidable lung cancer premature mortalities under each policy option considered in this paper. Table 6-5 presents estimates of the number of PM-related premature deaths from lung cancer, as well as the total mortality estimates previously presented.

The lung cancer mortality estimates are not additional deaths beyond the estimates from the Krewski et al., 2000 results. The mortality estimates from lung cancer are included in the total premature mortality estimates; the remaining cases of premature mortality (approximately 88 percent of the total) are from other causes, including both respiratory and cardio-vascular diseases.

In addition to the primary mortality estimate (which is based on Krewski et al., 2000 reanalysis of the American Cancer Society data), it is also possible to use other health studies as the basis of additional sensitivity estimates of mortality. Different health studies would produce different estimates of the avoidable cases of premature mortality. For example, a different estimate of the amount of premature mortality could be based on the Krewski et al., 2000 reanalysis of the 6 Cities (Dockery et al., 1993) cohort data. The reanalysis of the 6 Cities data produced a relative risk factor nearly three times as high as the reanalysis of the American Cancer Society data. Therefore, using the 6 Cities reanalysis result produces almost three times as large an estimate of the numbers of cases of attributable premature mortality. For No EGU scenario, the 6 Cities reanalysis-based mortality relationship estimates there would be 67, 719 attributable cases of premature mortality in 2010, compared with 23,604 using the American Cancer Society cohort results..

Another health effect associated with exposure to PM are asthma attacks. Because of possible double counting with endpoints that are included (such as emergency room visits for asthma and upper respiratory symptom days), EPA does not quantify the number of asthma attacks. Using the methods previously used by EPA, there are 554,448 PM-related asthma attacks in the 2010 No EGU analysis.

Table 6-1 2010 Health Benefits Estimates: Numbers of Cases Reduced

	CSA	No EGU	Carper	Straw	Jeffords
Mortality	7,861	23,604	10,430	11,100	16,575
Chronic Bronchitis	5,400	16,221	7,160	7,615	11,397
Heart Attacks	13,115	38,198	17,218	18,244	27,039
Hospital Admissions-Respiratory					
Chronic Lung, less Asthma(20-64)	374	1,127	496	527	791
Asthma(0-64)	651	1,946	860	912	1,362
Pneumonia(65+)	2,653	8,040	3,515	3,733	5,628
Chronic Lung(65+)	332	1,000	441	468	702
Total Hospital Admissions-Respiratory	4,010	12,113	5,313	5,640	8,484
Hospital Admissions Cardiovascular					
All Cardiovascular,(20-64)	1,332	4,028	1,778	1,893	2,829
All Cardiovascular,(65+)	1,903	5,707	2,521	2,677	4,006
Total Hospital Admissions-Cardiovascular	3,235	9,735	4,299	4,570	6,835
Emergency Room Visits for Asthma	8,316	25,999	11,108	11,811	18,205
Acute Bronchitis	12,522	37,705	16,614	17,669	26,554
Lower Respiratory Symptoms	142,621	429,980	189,214	201,197	302,678
Upper Respiratory Symptoms	113,707	348,823	151,390	161,069	243,760
Work Loss Days	1,050,415	3,186,036	1,395,098	1,483,765	2,231,223

Minor Restricted Activity Days	6,258,491	18,916,818	8,306,310	8,832,956	13,265,510

Table 6-2 2020 Health Benefits Estimates: Numbers of Cases Reduced

	CSA	Carper	Straw	Jeffords
Mortality	14,104	16,166	18,355	21,749
Chronic Bronchitis	8,770	10,048	11,422	13,586
Heart Attacks	23,009	26,280	29,798	35,230
Hospital Admissions - Respiratory				
Chronic Lung, less Asthma (20-64)	610	699	794	945
Asthma (0-64)	1,151	1,145	1,302	1,545
Pneumonia (65+)	4,972	5,705	6,496	7,749
Chronic Lung (65+)	650	746	848	1,008
Total Hospital Admissions - Respiratory	7,383	8,295	7,513	11,247
Hospital Admissions Cardiovascular				
All Cardiovascular, (20-64)	2,139	2,452	2,782	3,296
All Cardiovascular, (65+)	3,632	4,165	4,731	5,615
Total Hospital Admissions - Cardiovascular	5,771	6,617	7,513	8,911
Emergency Room Visits for Asthma	13,223	15,191	17,373	21,050
Acute Bronchitis	19,919	22,823	25,971	31,013
Lower Respiratory Symptoms	226,616	259,649	295,492	353,091
Upper Respiratory Symptoms	181,286	208,106	237,294	284,295
Work Loss Days	1,602,343	1,837,341	2,091,325	2,495,685
Minor Restricted Activity Days	9,519,433	10,910,946	12,413,325	14,800,704

Table 6-3 **2010 Value of Health Benefits (in millions of $1999)**

	CSA	NoEGU	Carper	Straw	Jeffords
Mortality	$51,974	$149,274	$65,959	$70,198	$104,823
Chronic Bronchitis	$2,046	$5,523	$2,438	$2,592	$3,881
Heart Attacks	$1,127	$3,284	$1,480	$1,568	$2,324
Hospital Admissions - Respiratory					
Chronic Lung, less Asthma (20-64)	$4	$13	$6	$6	$9
Asthma (0-64)	$5	$15	$7	$7	$11
Pneumonia (65+)	$47	$143	$63	$67	$100
Chronic Lung (65+)	$4	$13	$6	$6	$9
Total Hospital Admissions - Respiratory	$60	$187	$82	$87	$132
Hospital Admissions Cardiovascular					
All Cardiovascular, (20-64)	$30	$92	$41	$43	$64
All Cardiovascular, (65+)	$39	$116	$51	$54	$81
Total Hospital Admissions - Cardiovascular	$69	$206	$92	$97	$146
Emergency Room Visits for Asthma	$2	$7	$3	$3	$5
Acute Bronchitis	$5	$13	$6	$7	$10
Lower Respiratory Symptoms	$2	$7	$3	$3	$5
Upper Respiratory Symptoms	$3	$9	$4	$4	$6
Work Loss Days	$136	$367	$161	$171	$257
Minor Restricted Activity Days	$327	$956	$420	$447	$670

Table 6-4 2020 Value of Health Benefits (in millions of $1999)

	CSA 2020	Carper	Straw	Jeffords
Mortality	$106,996	$117,302	$133,186	$157,813
Chronic Bronchitis	$3,880	$3,995	$4,540	$5,401
Heart Attacks	$1,961	$2,240	$2,540	$3,003
Hospital Admissions - Respiratory				
Chronic Lung, less Asthma (20-64)	$7	$8	$9	$11
Asthma (0-64)	$9	$9	$10	$12
Pneumonia (65+)	$89	$102	$116	$138
Chronic Lung (65+)	$9	$10	$11	$14
Total Hospital Admissions - Respiratory	$114	$131	$149	$177
Hospital Admissions Cardiovascular				
All Cardiovascular, (20-64)	$49	$56	$63	$75
All Cardiovascular, (65+)	$74	$84	$96	$114
Total Hospital Admissions - Cardiovascular	$123	$140	$159	$188
Emergency Room Visits for Asthma	$4	$4	$5	$6
Acute Bronchitis	$8	$9	$10	$12
Lower Respiratory Symptoms	$4	$4	$5	$6
Upper Respiratory Symptoms	$5	$6	$6	$8
Work Loss Days	$208	$212	$241	$288
Minor Restricted Activity Days	$522	$578	$658	$784

Exhibit 6-1 **2010 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, 2010 Baseline**

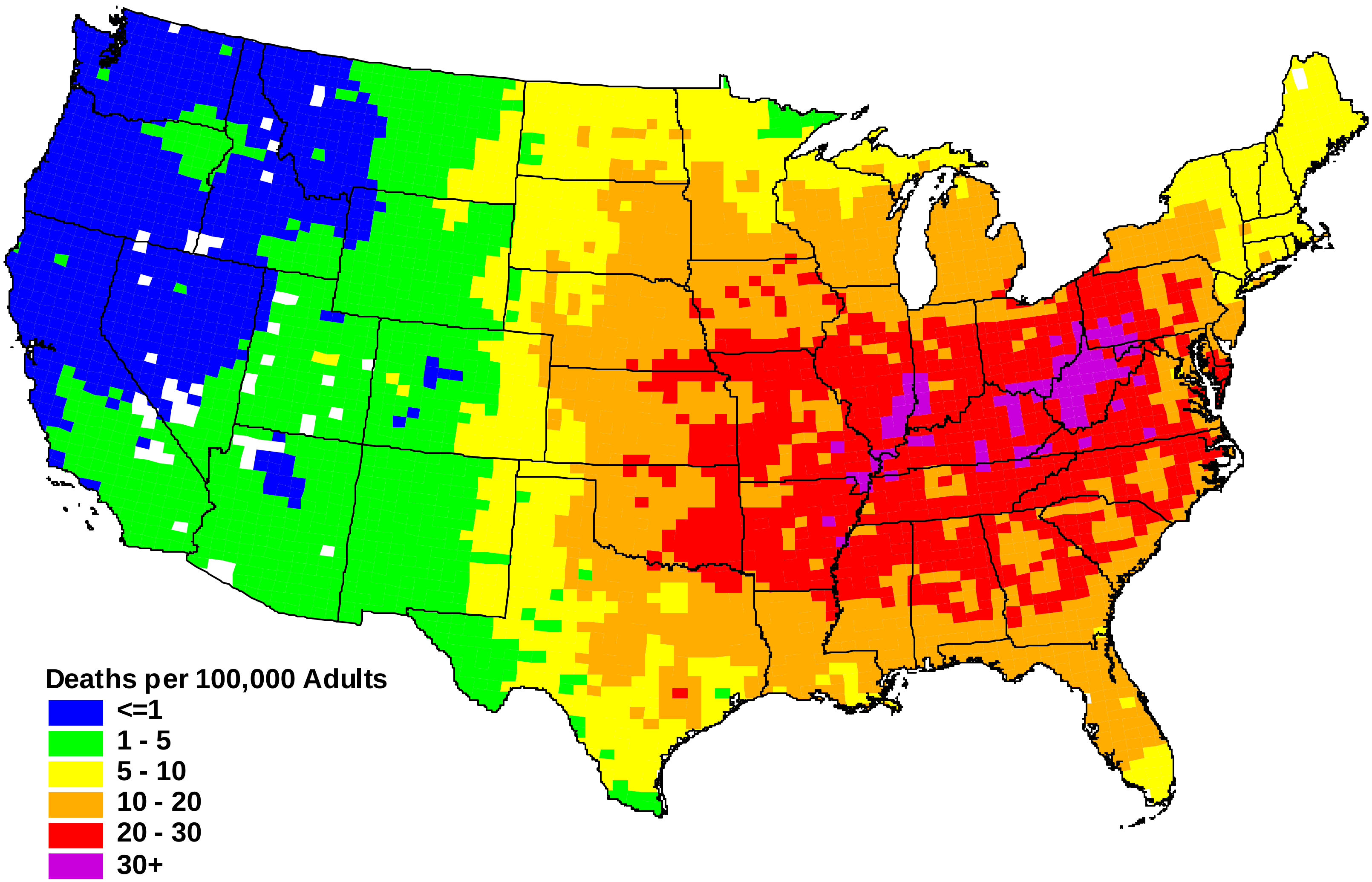

Exhibit 6-2 **2010 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Clear Skies Act**

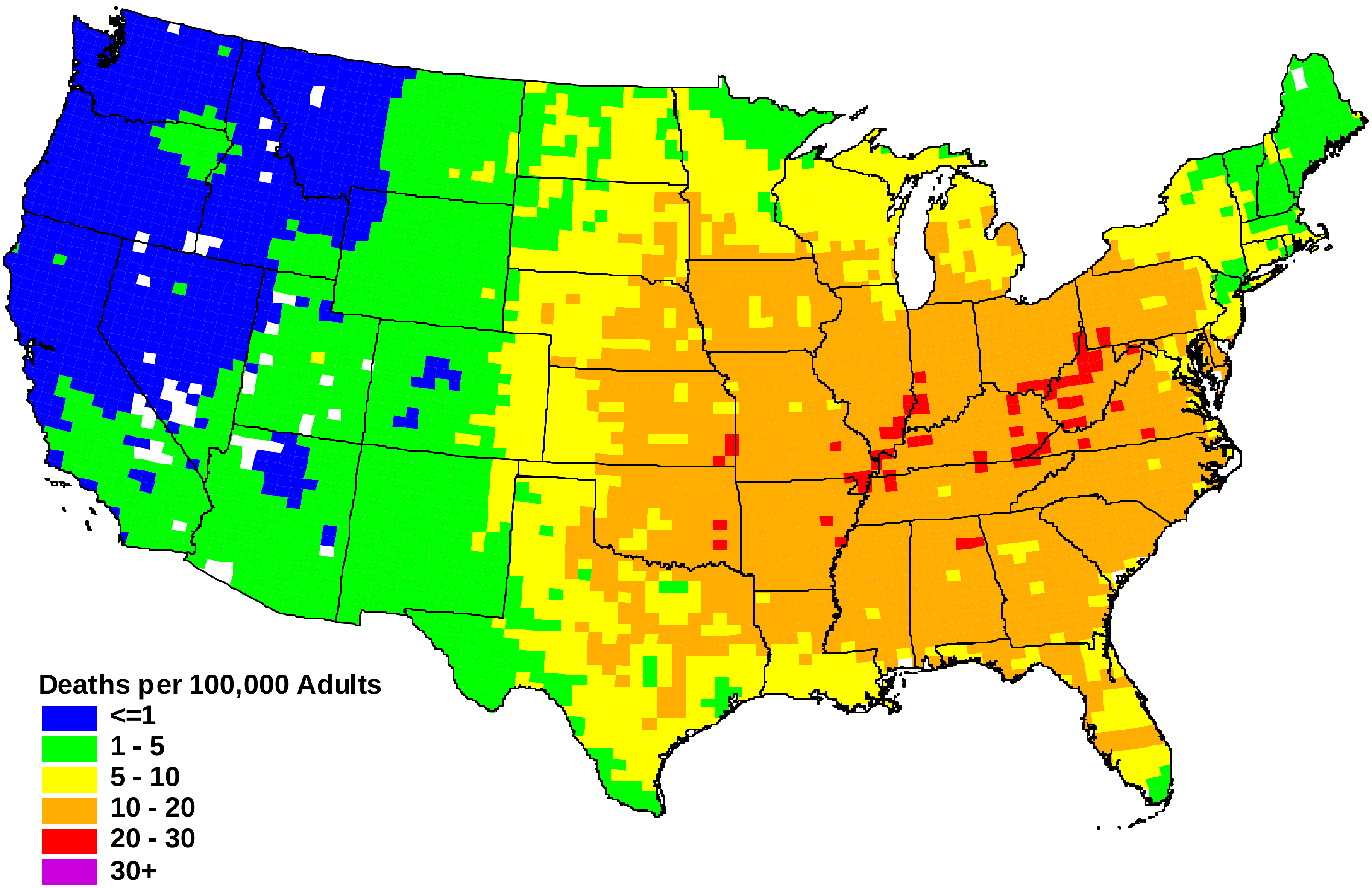

Exhibit 6-3 **2010 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Carper**

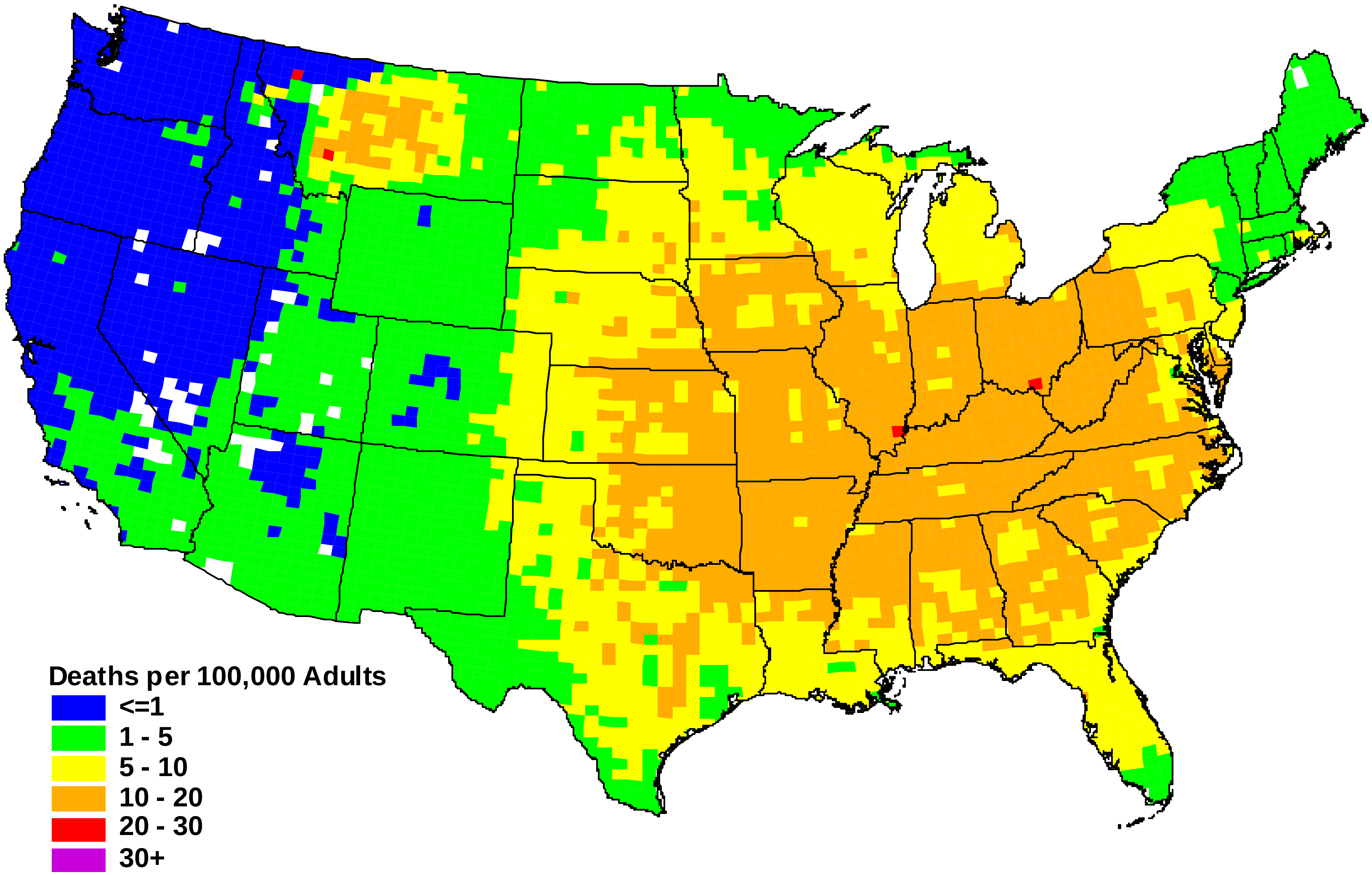

Exhibit 6-4 2010 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Straw Proposal

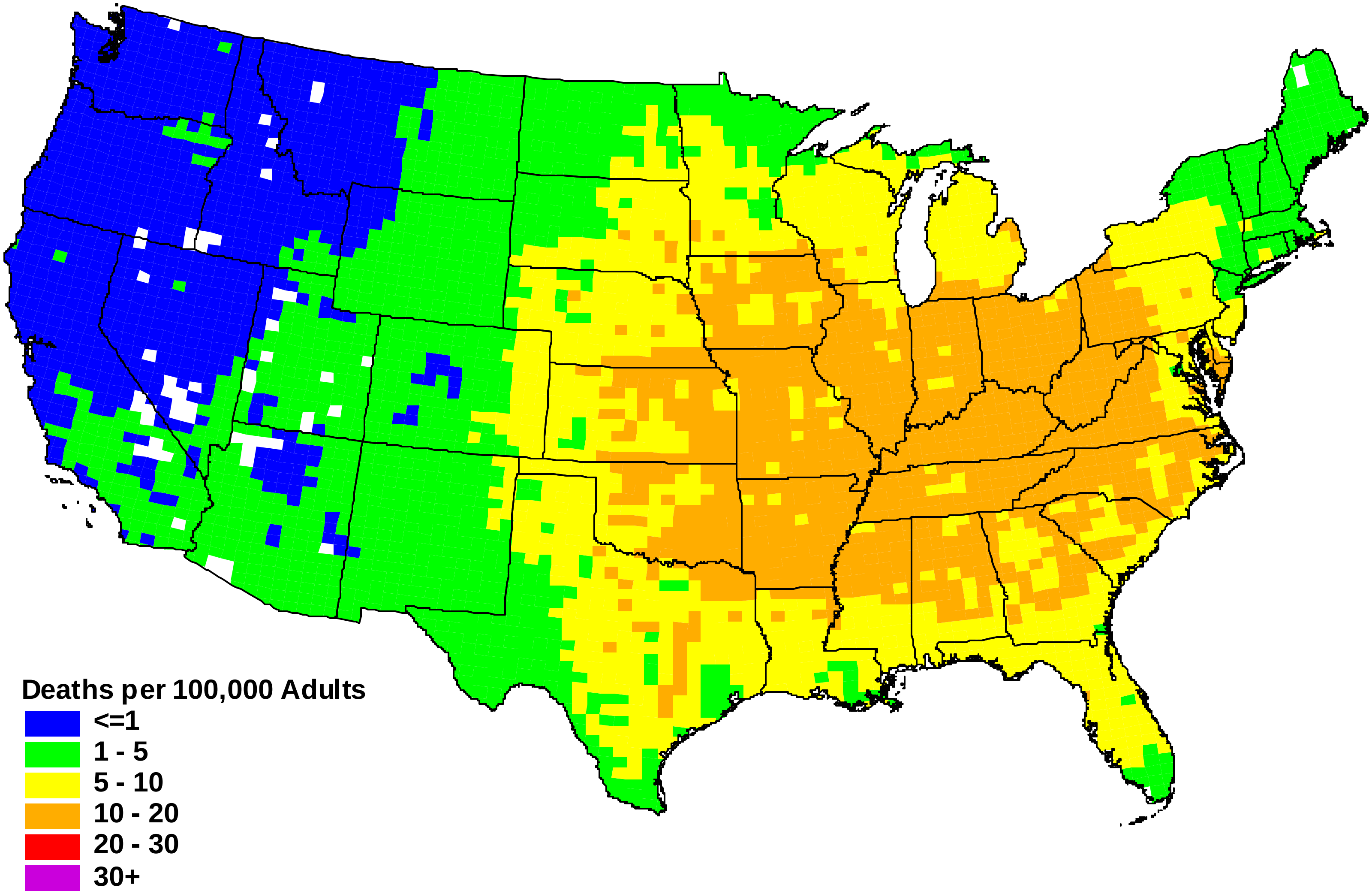

Exhibit 6-5 **2010 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Jeffords**

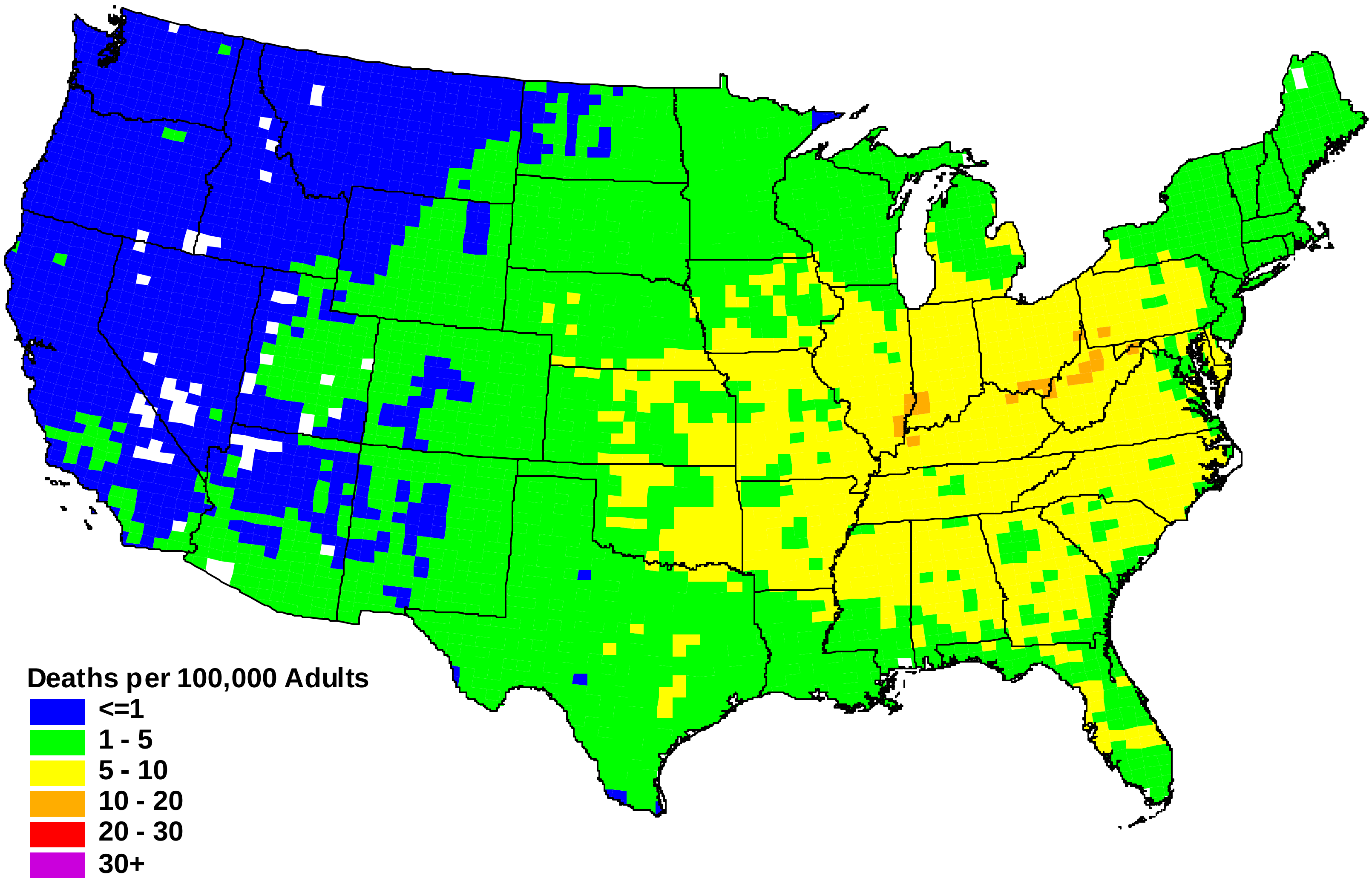

Exhibit 6-6 2020 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, Baseline

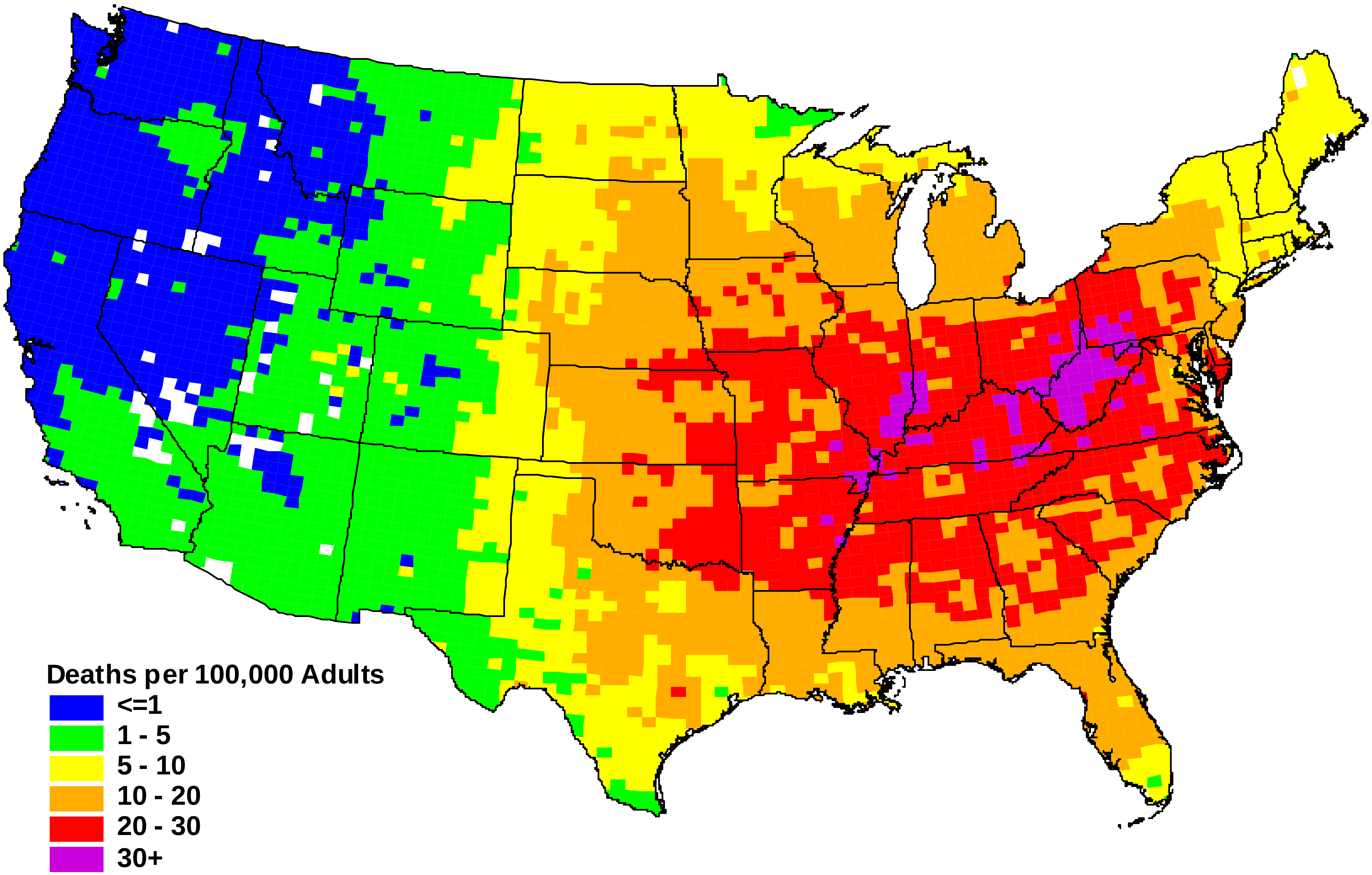

Exhibit 6-7 **2020 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Clear Skies Act**

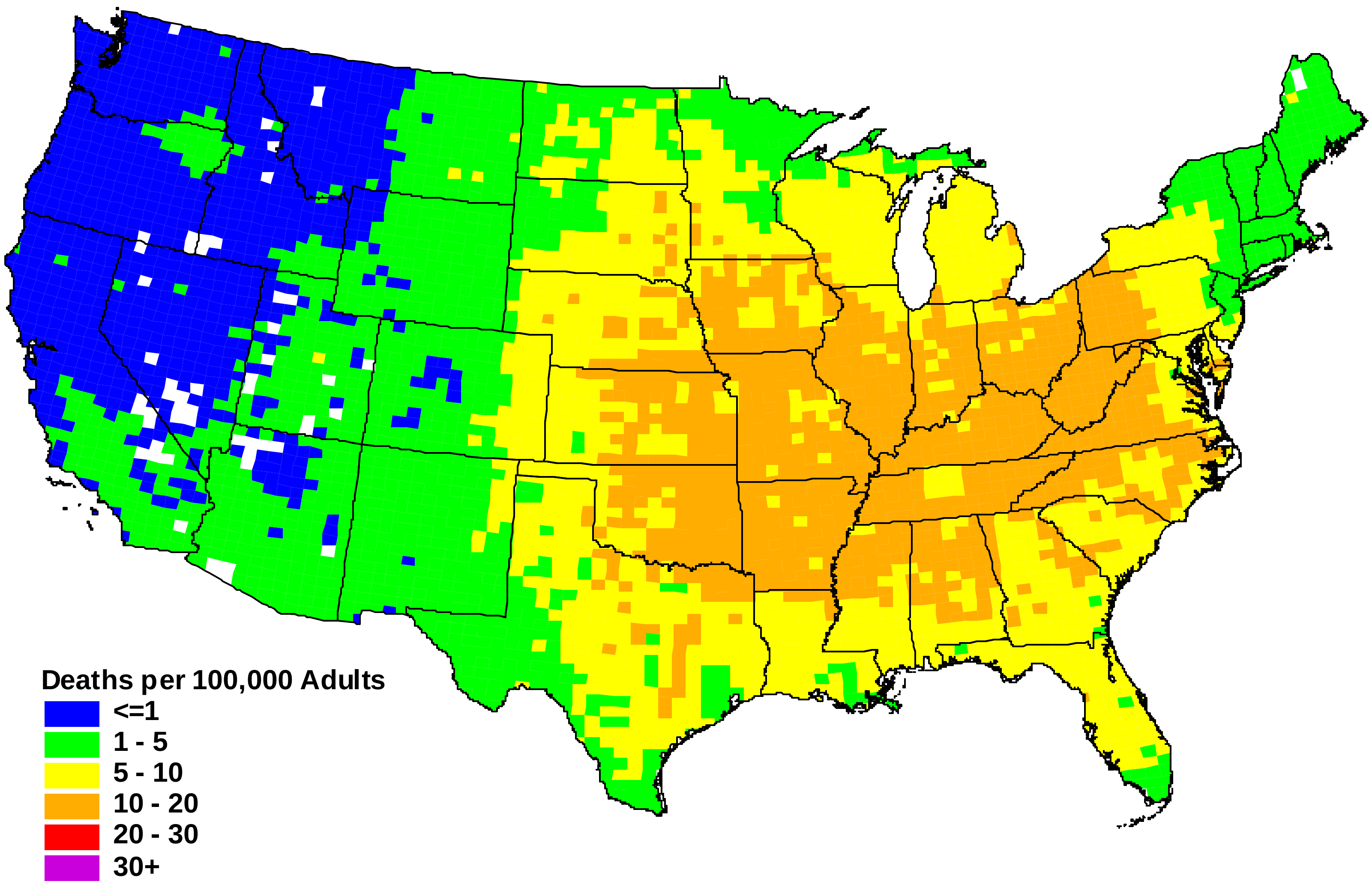

Exhibit 6-8 **2020 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Carper**

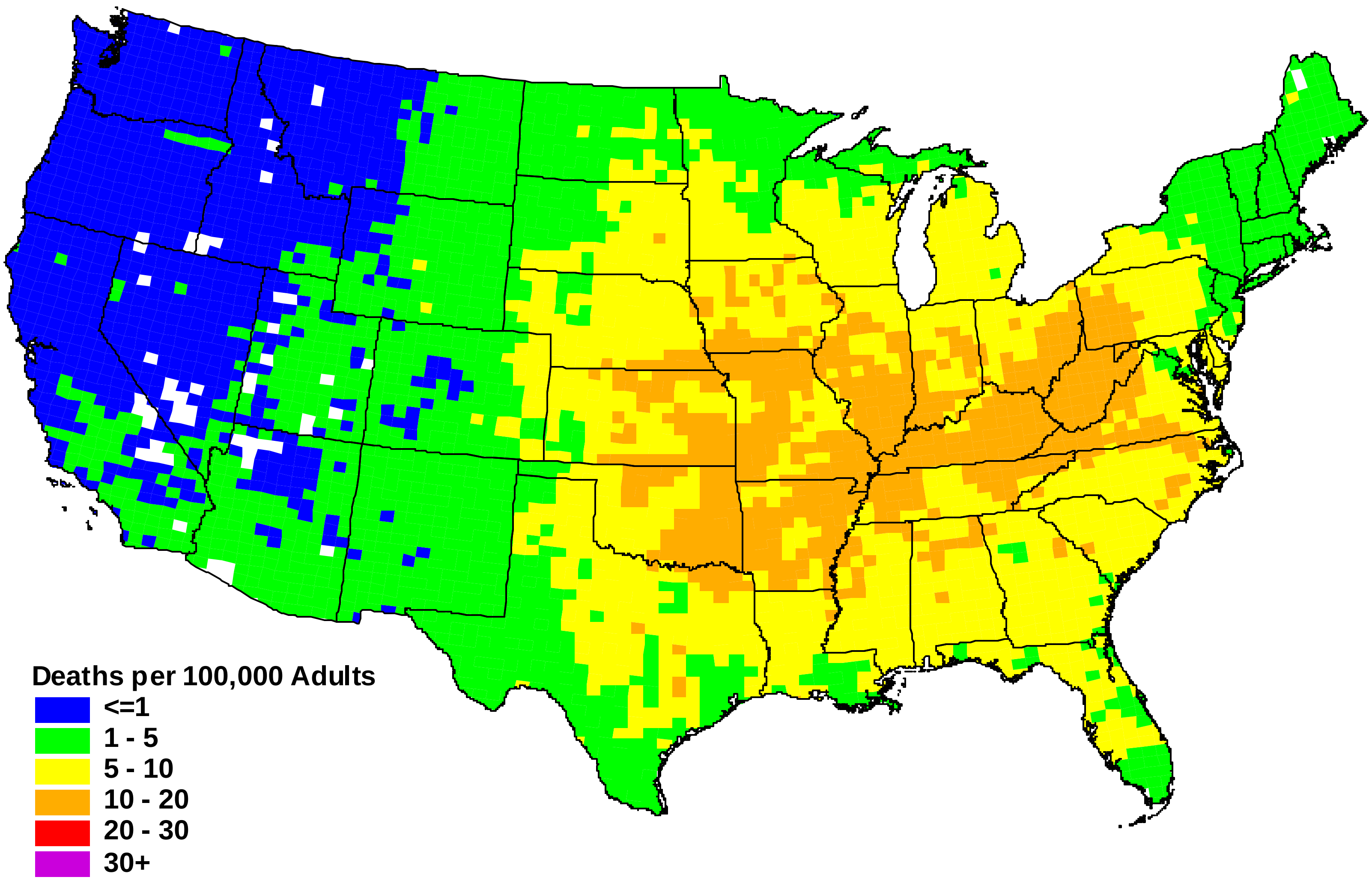

Exhibit 6-9 **2020 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Straw Proposal**

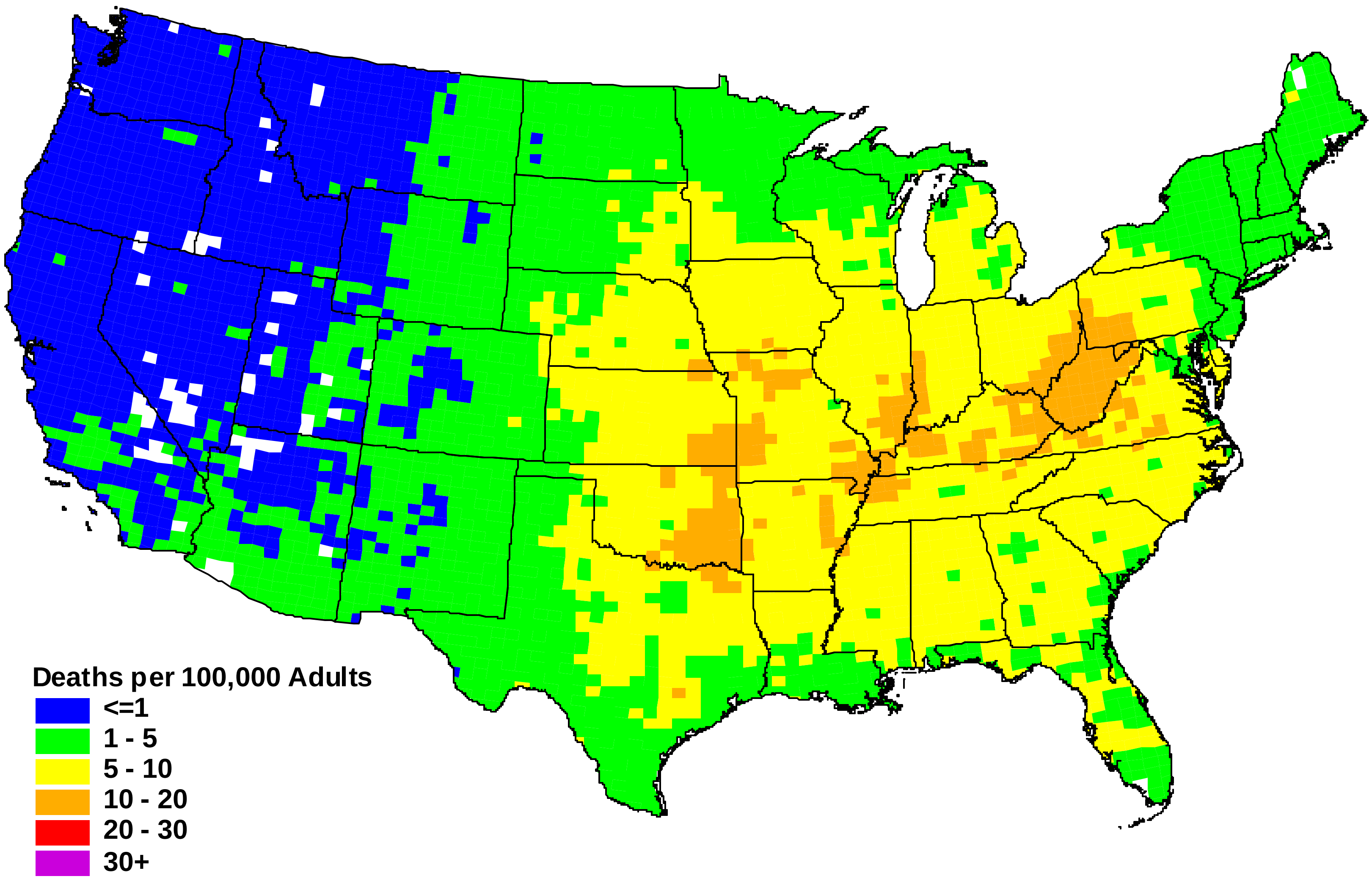

Exhibit 6-10 2020 Premature Mortality Risk Attributable to $PM_{2.5}$ from Power Plants, With Jeffords

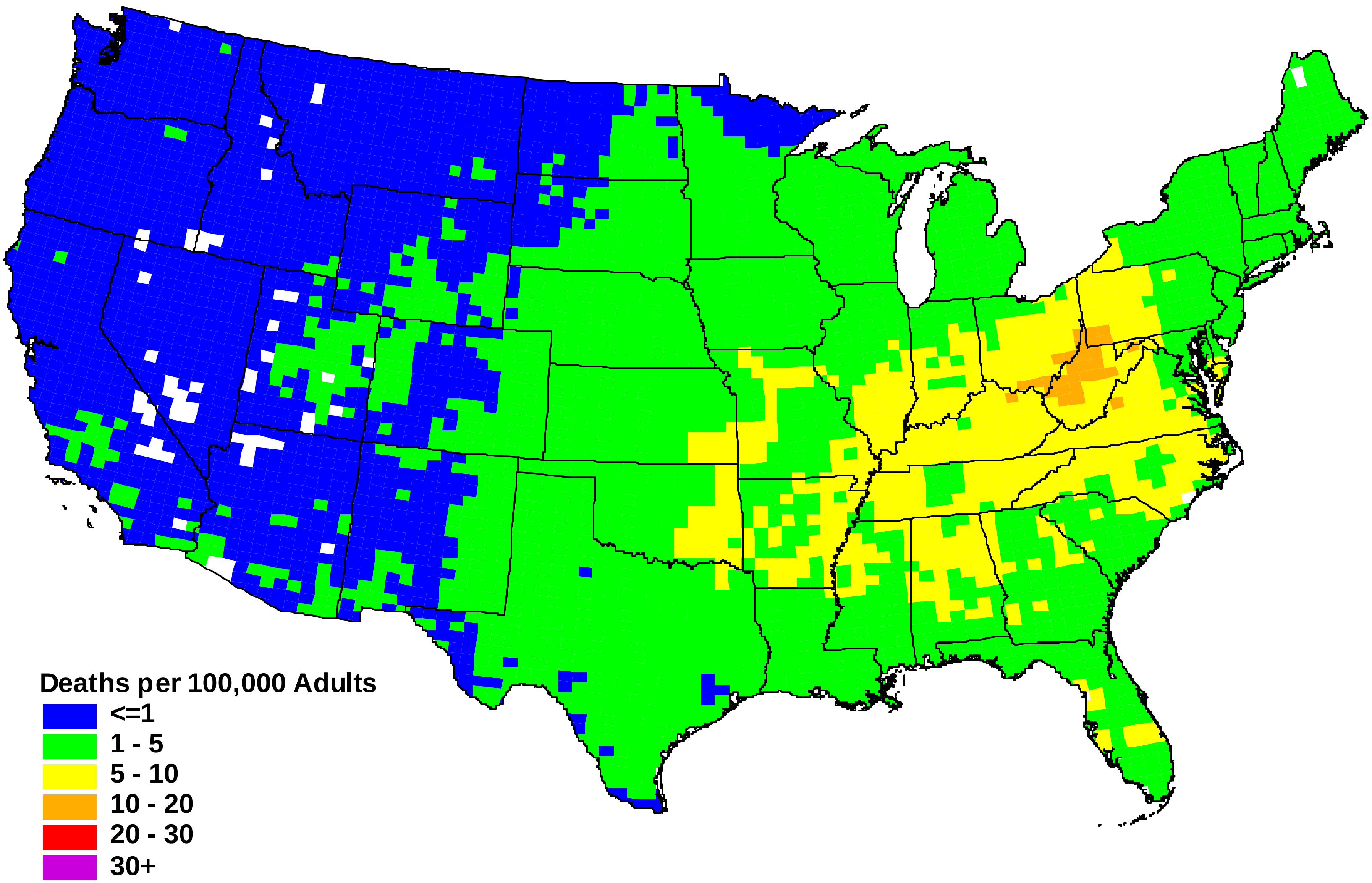

Table 6.5 Lung Cancer Mortality Estimates

	Lung Cancer Mortality (Pope et al., 2002)	Adult Mortality (Krewski et al., 2000)
2010		
CSA	944	7,861
No EGU	2,826	23,604
Carper	1,253	10,430
Straw	1,334	11,100
Jeffords	1,990	16,575
2020		
CSA	1,758	14,104
Carper	2,015	16,166
Straw	2,288	18,355
Jeffords	2,711	21,749

7 Non-Attainment Analysis

The reductions in ambient levels of $PM_{2.5}$ will not only reduce the numbers of adverse health effects attributable to PM, but will also have an influence on what portions of the country are predicted to exceed the National Ambient Air Quality Standards (NAAQS) for PM. In 2001 EPA issued draft guidance that describes a procedure for combining monitored data with REMSAD results to estimate future concentrations of PM2.5. The procedure, known as the Speciated Modeled Attainment Test (SMAT) uses estimates of current and future levels of six components of $PM_{2.5}$. The six components of $PM_{2.5}$ used in a SMAT analysis are: sulfates, nitrates, organic carbon, elemental carbon, crustal material, and un-attributed mass.

EPA used the SMAT technique to estimate the numbers of counties that will not attain the annual mean $PM_{2.5}$ NAAQS levels with and without the Clear Skies Act. They have also conducted SMAT analysis for other proposed rules currently under consideration. The most complete description of the SMAT method is available as part of the documentation of the January 30, 2004 proposed Clean Air Interstate Rule (CAIR). In particular, the SMAT procedures are described in "Appendix E: Speciated Modeled Attainment Test (SMAT) Documentation", a part of the *Technical Support Document for the Interstate Air Quality Rule Air Quality Modeling Analysis* available online at http://www.epa.gov/interstateairquality/tsd0162.pdf.

While the method used in the SMAT have not changed since EPA conducted the analysis of the Clear Skies Act, for the CAIR and other subsequent rules EPA has updated and refined some of the monitor data used in a SMAT.

This chapter provides the results of a SMAT analysis on each of the policy options considered in this report. While the method used in the SMAT have not changed since EPA conducted the analysis of the Clear Skies Act, for the CAIR and other subsequent rules EPA has updated and refined some of the historic monitor data and analysis used in a SMAT. The analysis in this chapter uses the same historic monitor data and analysis as the was used in EPA's analysis of the Clear Skies Act.

EPA's SMAT method is only applicable to counties with adequate $PM_{2.5}$. monitor data. The SMAT analysis of the Clear Skies Act used actual monitor data from 1999 through 2001, and analyzed a total of 307 counties. While these counties include many of the most heavily populated counties in the United States, a sizable portion of the population lives in the 2,802 counties that did not have sufficient $PM_{2.5}$ monitors in 1999-2001 to be included in those analyses.

The results of the SMAT analysis for the policy options examined in this report are included in Table 7-1. The analysis of the Clear Skies Act is from the EPA analysis. County results, including the Design Value (estimated $PM_{2.5}$ level at the highest monitor in the county) are presented in Appendix C.

Table 7-1 SMAT Results: Estimated Number of Non-Attainment Counties

All Years	# Counties Analyzed	307
Year	Policy Option	# of Counties Exceeding Annual Mean Standard
'99-'01	Observed Monitors	129
	Base Case	80
	Clear Skies	38
	Jeffords	16
	Straw	24
	Carper	27
	No EGU	13
2020	Base Case	53
	Clear Skies	18
	Jeffords	13
	Straw	13
	Carper	15

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Appendix A: Particulate Matter C-R Functions

Appendix A describes the concentration-response functions that we use in this analysis. Note that for all of the concentration-response functions we define ΔPM as $PM_{baseline}$ - $PM_{control}$, and we define the change in incidence as: - ($incidence_{control}$ - $incidence_{baseline}$).

Mortality

There are two types of exposure to PM that may result in premature mortality. Short-term exposure may result in excess mortality on the same day or within a few days of exposure. Long-term exposure over, say, a year or more, may result in mortality in excess of what it would be if PM levels were generally lower, although the excess mortality that occurs will not necessarily be associated with any particular episode of elevated air pollution levels. In other words, long-term exposure may capture a facet of the association between PM and mortality that is not captured by short-term exposure.

Mortality (Krewski et al., 2000) Based on ACS Cohort: Mean $PM_{2.5}$

The C-R function to estimate the change in long-term mortality is:

$$\Delta Mortality = -\left[y_0 \cdot (e^{-b \cdot \Delta PM_{2.5}} - 1)\right] \cdot pop,$$

where:

y_0 = county-level all-cause annual death rate per person ages 30 and older
β = $PM_{2.5}$ coefficient = 0.0046257
$\Delta PM_{2.5}$ = change in annual <u>mean</u> $PM_{2.5}$ concentration
pop = population of ages 30 and older
σ_β = standard error of β = 0.0012046

Incidence Rate. To estimate county-specific baseline mortality incidence among individuals ages 30 and over, this analysis used the average annual all-cause county mortality rate from 1994 through 1996 (U.S. Centers for Disease Control, 1999). Note that the Krewski et al. (2000) replication of Pope et al. (1995) used the same all-cause mortality when estimating the impact of PM.

Coefficient Estimate (β). The coefficient (β) is estimated from the relative risk (1.12) associated with a change in mean exposure of 24.5 $\mu g/m^3$ (based on the range from the original ACS study) (Krewski et al., 2000, Part II - Table 31, 63 city Dichotomous sampler).

$$b = \frac{\ln(1.12)}{(24.5)} = 0.0046257.$$

Standard Error (σ_β). The standard error (σ_β) was calculated as the average of the standard errors implied by the reported lower and upper bounds of the relative risk (Krewski et al., 2000, Part II - Table 31).

$$s_{b,high} = \frac{b_{high} - b}{1.96} = \frac{\left(\frac{\ln(1.19)}{24.5} - \frac{\ln(1.12)}{24.5}\right)}{1.96} = 0.0012625$$

$$s_{b,low} = \frac{b - b_{low}}{1.96} = \frac{\left(\frac{\ln(1.12)}{24.5} - \frac{\ln(1.06)}{24.5}\right)}{1.96} = 0.0011466$$

$$s_b = \frac{s_{high} + s_{low}}{2} = 0.0012046$$

Chronic Illness

Schwartz (1993) and Abbey et al. (1993; 1995c) provide evidence that PM exposure over a number of years gives rise to the development of chronic bronchitis in the U.S., and a recent study by McDonnell et al. (1999) provides evidence that ozone exposure is linked to the development of asthma in adults. These results are consistent with research that has found chronic exposure to pollutants leads to declining pulmonary functioning (Detels et al., 1991; Ackermann-Liebrich et al., 1997; Abbey et al., 1998).[27]

Chronic Bronchitis (Abbey et al., 1995c, California)

Abbey et al. (1995c) examined the relationship between estimated $PM_{2.5}$ (annual mean from 1966 to 1977), PM_{10} (annual mean from 1973 to 1977) and TSP (annual mean from 1973 to 1977) and the same chronic respiratory symptoms in a sample population of 1,868 Californian Seventh Day Adventists. The initial survey was conducted in 1977 and the final survey in 1987. To ensure a better estimate of exposure, the study participants had to have been living in the same area for an extended period of time. In single-pollutant models, there was a statistically significant $PM_{2.5}$ relationship with development of chronic bronchitis, but not for AOD or asthma; PM_{10} was significantly associated with chronic bronchitis and AOD; and TSP was significantly associated with all cases of all three chronic symptoms. Other pollutants were not examined. The C-R function is based on the results of the single pollutant model presented in Table 2.

Single Pollutant Model

The estimated coefficient (0.0137) is presented for a one $\mu g/m^3$ change in $PM_{2.5}$ (Abbey et al., 1995c, Table 2). The standard error is calculated from the reported relative risk (1.81) and 95% confidence interval (0.98-3.25) for a 45 $\mu g/m^3$ change in $PM_{2.5}$ (Abbey et al., 1995c, Table 2).

[27] There are a limited number of studies that have estimated the impact of air pollution on chronic bronchitis. An important hindrance is the lack of health data and the associated air pollution levels over a number of years.

Functional Form: Logistic
Coefficient: 0.0137
Standard Error: 0.00680
Incidence Rate: annual bronchitis incidence rate per person (Abbey et al., 1993, Table 3) = 0.00378
Population: population of ages 27 and older[28] without chronic bronchitis = 95.57%[29] of population 27+

Heart Attacks

Acute Myocardial Infarction (Heart Attacks), Nonfatal (Peters et al., 2001)

Peters et al. (2001) studied the relationship between increased particulate air pollution and onset of heart attacks in the Boston area from 1995 to 1996. The authors used air quality data for PM10, PM10-2.5, PM2.5,"black carbon", O3, CO, NO2, and SO2 in a case-crossover analysis. For each subject, the case period was matched to three control periods, each 24 hours apart. In univariate analyses, the authors observed a positive association between heart attack occurrence and PM2.5 levels hours before and days before onset. The authors estimated multivariate conditional logistic models including two-hour and twenty-four hour pollutant concentrations for each pollutant. They found significant and independent associations between heart attack occurrence and both two-hour and twenty-four hour PM2.5 concentrations before onset. Significant associations were observed for PM10 as well. None of the other particle measures or gaseous pollutants were significantly associated with acute myocardial infarction for the two hour or twenty-four hour period before onset.

The patient population for this study was selected from health centers across the United States. The mean age of participants was 62 years old, with 21% of the study population under the age of 50. In order to capture the full magnitude of heart attack occurrence potentially associated with air pollution and because age was not listed as an inclusion criteria for sample selection, we apply an age range of 18 and over in the C-R function. According to the National Hospital Discharge Survey, there were no hospitalizations for heart attacks among children <15 years of age in 1999 and only 5.5% of all hospitalizations occurred in 15-44 year olds (Popovic, 2001, Table 10).

Single Pollutant Model

The coefficient and standard error are calculated from an odds ratio of 1.62 (95% CI 1.13-2.34) for a 20 $\mu g/m^3$ increase in twenty-four hour average $PM_{2.5}$ (Peters et al., 2001, Table 4, p. 2813).

Functional Form: Logistic
Coefficient: 0.024121

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[28] Using the same data set, Abbey et al. (1995a, p. 140) reported that the respondents in 1977 ranged in age from 27 to 95.

[29] The American Lung Association (2002b, Table 4) reports a chronic bronchitis prevalence rate for ages 18 and over of 4.43% (American Lung Association, 2002b, Table 4).

Standard Error: 0.009285

Incidence Rate: region-specific daily nonfatal heart attack rate per person 18+ = 93% of region-specific daily heart attack hospitalization rate (ICD code 410) [30]

Population: population of ages 18 and older

Hospital Admissions

There is a wealth of epidemiological information on the relationship between air pollution and hospital admissions for various respiratory and cardiovascular diseases; in addition, some studies have examined the relationship between air pollution and emergency room (ER) visits. Because most emergency room visits do not result in an admission to the hospital -- the majority of people going to the ER are treated and return home -- we treat hospital admissions and ER visits separately, taking account of the fraction of ER visits that do get admitted to the hospital, as discussed below.

Hospital admissions require the patient to be examined by a physician, and on average may represent more serious incidents than ER visits (Lipfert, 1993, p. 230). The two main groups of hospital admissions estimated in this analysis are respiratory admissions and cardiovascular admissions. There is not much evidence linking air pollution with other types of hospital admissions. The only types of ER visits that have been linked to air pollution in the U.S. or Canada are asthma-related visits.

Hospital Admissions for Chronic Lung Disease Less Asthma *(*Moolgavkar, 2000c)

Multipollutant Model ($PM_{2.5}$ and CO)

In a model with CO, the coefficient and standard error are calculated from an estimated percent change of 2.0[31] and t-statistic of 2.2 for a 10 μg/m^3 increase in $PM_{2.5}$ in the two-day lag model (Moolgavkar, 2000c, Table 4, p. 81).

Functional Form: Log-linear

Coefficient: 0.0020

Standard Error: 0.000909

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[30]This estimate assumes that all heart attacks that are not instantly fatal will result in a hospitalization. In addition, Rosamond et al. (1999) report that approximately six percent of male and eight percent of female hospitalized heart attack patients die within 28 days (either in or outside of the hospital). We applied a factor of 0.93 to the number of hospitalizations to estimate the number of nonfatal heart attacks per year.

[31] In a log-linear model, the percent change is equal to (RR - 1) * 100. In this study, Moolgavkar defines and reports the "estimated" percent change as (log RR * 100). Because the relative risk is close to 1, RR-1 and log RR are essentially the same. For example, a true percent change of 2.0 would result in a relative risk of 1.020 and coefficient of 0.001980. The "estimated" percent change, as reported by Moolgavkar, of 2.0 results in a relative risk of 1.020201 and coefficient of 0.002.

Incidence Rate: region-specific daily hospital admission rate for chronic lung disease admissions per person 18-64 (ICD codes 490-492, 494-496)[32]

Population: population of ages 18 to 64

Hospital Admissions for Asthma (Sheppard et al., 1999, Seattle)

Sheppard et al. (1999) studied the relation between air pollution in Seattle and nonelderly (<65) hospital admissions for asthma from 1987 to 1994. They used air quality data for PM_{10}, $PM_{2.5}$, coarse $PM10_{10-2.5}$, SO_2, ozone, and CO in a Poisson regression model with control for time trends, seasonal variations, and temperature-related weather effects.[33] They found asthma hospital admissions associated with PM_{10}, $PM_{2.5}$, $PM_{10-2.5}$, CO, and ozone. They did not observe an association for SO_2. They found PM and CO to be jointly associated with asthma admissions. The best fitting co-pollutant models were found using ozone. However, ozone data was only available April through October, so they did not consider ozone further. For the remaining pollutants, the best fitting models included $PM_{2.5}$ and CO. Results for other co-pollutant models were not reported. The $PM_{2.5}$ C-R function is based on the multipollutant model.

Multipollutant Model ($PM_{2.5}$ and CO)

The coefficient and standard error for the co-pollutant model with CO are calculated from a relative risk of 1.03 (95% CI 1.01-1.06) for an 11.8 $\mu g/m^3$ increase[34] in $PM_{2.5}$ (Sheppard et al., 1999, p. 28).

Functional Form: Log-linear

Coefficient: 0.002505

Standard Error: 0.001045

Incidence Rate: region-specific daily hospital admission rate for asthma admissions per person <65 (ICD code 493)

Population: population of ages 65 and under

Hospital Admissions for Pneumonia (Lippmann et al., 2000, Detroit)

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[32] Moolgavkar (2000c) reports results for ICD codes 490-496. In order to avoid double counting non-elderly asthma hospitalizations (ICD code 493) with Sheppard et al. (1999) in a total benefits estimation, we have excluded ICD code 493 from the baseline incidence rate used in this function.

[33] $PM_{2.5}$ levels were estimated from light scattering data.

[34] The reported Inter Quartile Range(11.8 $\mu g/m^3$) change in the abstract and text is smaller than reported in Table 3. We assume the change reported in the abstract and text to be correct because greater number of significant figures are reported.

Lippmann et al. (2000) studied the association between particulate matter and daily mortality and hospitalizations among the elderly in Detroit, MI. Data were analyzed for two separate study periods, 1985-1990 and 1992-1994. The 1992-1994 study period had a greater variety of data on PM size and was the main focus of the report. The authors collected hospitalization data for a variety of cardiovascular and respiratory endpoints. They used daily air quality data for PM_{10}, $PM_{2.5}$, and $PM_{10-2.5}$ in a Poisson regression model with generalized additive models (GAM) to adjust for nonlinear relationships and temporal trends. In single pollutant models, all PM metrics were statistically significant for pneumonia (ICD codes 480-486), $PM_{10-2.5}$ and PM_{10} were significant for ischemic heart disease (ICD code 410-414), and $PM_{2.5}$ and PM_{10} were significant for heart failure (ICD code 428). There were positive, but not statistically significant associations, between the PM metrics and COPD (ICD codes 490-496) and dysrhythmia (ICD code 427). In separate co-pollutant models with PM and either ozone, SO_2, NO_2, or CO, the results were generally comparable. The $PM_{2.5}$ C-R function is based on the results of the co-pollutant model with ozone.

Multipollutant Model ($PM_{2.5}$ and ozone)

The co-pollutant coefficient and standard error are calculated from a relative risk of 1.175 (95% CI 1.026-1.345) for a 36 $\mu g/m^3$ increase in $PM_{2.5}$ (Lippmann et al., 2000, Table 14, p. 26).

Functional Form: Log-linear

Coefficient: 0.004480

Standard Error: 0.001918

Incidence Rate: region-specific daily hospital admission rate for pneumonia admissions per person 65+ (ICD codes 480-487)

Population: population of ages 65 and older

Hospital Admissions for Chronic Lung Disease

The following two studies, Lippmann (2000) and Moolgavkar (2000b), were combined together using a random/fixed effects pooling method. The random/fixed effects weighting for each study was as follows: Lippmann(2000) study was 15% and Moolgavkar(2000b) study was 85%. The pertinent information for the individual studies has been included below.

1) Lippmann et al., 2000, Detroit

Lippmann et al. (2000) studied the association between particulate matter and daily mortality and hospitalizations among the elderly in Detroit, MI. Data were analyzed for two separate study periods, 1985-1990 and 1992-1994. The 1992-1994 study period had a greater variety of data on PM size and was the main focus of the report. The authors collected hospitalization data for a variety of cardiovascular and respiratory endpoints. They used daily air quality data for PM_{10}, $PM_{2.5}$, and $PM_{10-2.5}$ in a Poisson regression model with generalized additive models (GAM) to adjust for nonlinear relationships and temporal trends. In single pollutant models, all PM metrics were statistically significant for pneumonia (ICD codes 480-486), $PM_{10-2.5}$ and PM_{10} were significant for ischemic heart disease (ICD code 410-414), and $PM_{2.5}$ and PM_{10} were significant for heart failure (ICD code 428). There were positive, but not statistically significant associations, between the PM metrics and COPD (ICD codes 490-496) and dysrhythmia (ICD code 427). In separate co-pollutant models with PM and either ozone, SO_2, NO_2, or CO, the results were generally comparable. The $PM_{2.5}$ C-R function is based on results of the co-pollutant model with ozone.

Multipollutant Model ($PM_{2.5}$ and ozone)

The co-pollutant coefficient and standard error are calculated from a relative risk of 1.040 (95% CI 0.877-1.234) for a 36 $\mu g/m^3$ increase in $PM_{2.5}$ (Lippmann et al., 2000, Table 14, p. 26).

Functional Form: Log-linear

Coefficient: 0.001089

Standard Error: 0.002420

Incidence Rate: region-specific daily hospital admission rate for chronic lung disease admissions per person 65+ (ICD codes 490-496)

Population: population of ages 65 and older

2) Moolgavkar, 2000b

Moolgavkar (2000b) examined the association between air pollution and COPD hospital admissions (ICD 490-496) in the Chicago, Los Angeles, and Phoenix metropolitan areas. He collected daily air pollution data for ozone, SO_2, NO_2, CO, and PM_{10} in all three areas. $PM_{2.5}$ data was available only in Los Angeles. The data were analyzed using a Poisson regression model with generalized additive models to adjust for temporal trends. Separate models were run for 0 to 5 day lags in each location. Among the 65+ age group in Chicago and Phoenix, weak associations were observed between the gaseous pollutants and admissions. No consistent associations were observed for PM_{10}. In Los Angeles, marginally significant associations were observed for $PM_{2.5}$, which were generally lower than for the gases. In co-pollutant models with CO, the $PM_{2.5}$ effect was reduced. Similar results were observed in the 0-19 and 20-64 year old age groups.

The $PM_{2.5}$ C-R functions are based on the co-pollutant models ($PM_{2.5}$ and CO) reported for the 20-64 and 65+ age groups. Since the true PM effect is most likely best represented by a distributed lag model, then any single lag model should underestimate the total PM effect. As a result, we selected the lag models with the greatest effect estimates for use in the C-R functions.

Ages 65 and older

Multipollutant Model ($PM_{2.5}$ and CO)

In a model with CO, the coefficient and standard error are calculated from an estimated percent change of 0.8[35] and t-statistic of 0.8 for a 10 $\mu g/m^3$ increase in $PM_{2.5}$ in the two-day lag model (Moolgavkar, 2000b, Table 3, p. 80).

Functional Form: Log-linear

Coefficient: 0.0008

Standard Error: 0.001000

Incidence Rate: region-specific daily hospital admission rate for chronic lung disease admissions per person 65+ (ICD codes 490-496)

Population: population of ages 65 and older

Hospital Admissions, All Cardiovascular(20-64) (Moolgavkar, 2000a, Los Angeles)

Moolgavkar (2000a) examined the association between air pollution and cardiovascular hospital admissions (ICD 390-448) in the Chicago, Los Angeles, and Phoenix metropolitan areas. He collected daily air pollution data for ozone, SO_2, NO_2, CO, and PM_{10} in all three areas. $PM_{2.5}$ data was available only in Los Angeles. The data were analyzed using a Poisson regression model with generalized additive models to adjust for temporal trends. Separate models were run for 0 to 5 day lags in each location. In a single pollutant model, $PM_{2.5}$ was statistically significant for lag 0 and lag 1. In co-pollutant models with CO, the $PM_{2.5}$ effect dropped out and CO remained significant. For ages 20-64, SO_2 and CO exhibited the strongest effect and any $PM_{2.5}$ effect dropped out in co-pollutant models with CO. The $PM_{2.5}$ C-R functions are based on co-pollutant ($PM_{2.5}$ and CO) models.

Ages 18 to 64[36]

Multipollutant Model ($PM_{2.5}$ and CO)

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[35] In a log-linear model, the percent change is equal to (RR - 1) * 100. In this study, Moolgavkar defines and reports the "estimated" percent change as (log RR * 100). Because the relative risk is close to 1, RR-1 and log RR are essentially the same. For example, a true percent change of 0.8 would result in a relative risk of 1.008 and coefficient of 0.000797. The "estimated" percent change, as reported by Moolgavkar, of 0.8 results in a relative risk of 1.008032 and coefficient of 0.0008.

[36] Although Moolgavkar (2000a) reports results for the 20-64 year old age range, for comparability to other studies, we apply the results to the population of ages 18 to 64.

In a model with CO, the coefficient and standard error are calculated from an estimated percent change of 0.9[37] and t-statistic of 1.8 for a 10 μg/m^3 increase in $PM_{2.5}$ in the zero lag model (Moolgavkar, 2000a, Table 4, p. 1203).

Functional Form: Log-linear

Coefficient: 0.0009

Standard Error: 0.000500

Incidence Rate: region-specific daily hospital admission rate for all cardiovascular admissions per person ages 18 to 64 (ICD codes 390-409, 411-459)[38]

Population: population of ages 18 to 64

Hospital Admissions for All Cardiovascular(65+)

The following four studies, Moolgavkar (2000a), and Lippmann (2000) Dysrhythmia, Lippmann (2000) Heart Failure, and Lippmann (2000) Ischemic Heart Disease were combined together using a random/fixed effects pooling method. The random/fixed effects weighting for each study was as follows: Moolgavkar(2000a) study was 76% and the sum of the three Lippmann studies was weighted 24%. The pertinent information for the individual studies has been included below.

1) Moolgavkar, 2000a, Los Angeles

Moolgavkar (2000a) examined the association between air pollution and cardiovascular hospital admissions (ICD 390-448) in the Chicago, Los Angeles, and Phoenix metropolitan areas. He collected daily air pollution data for ozone, SO_2, NO_2, CO, and PM_{10} in all three areas. $PM_{2.5}$ data was available only in Los Angeles. The data were analyzed using a Poisson regression model with generalized additive models to adjust for temporal trends. Separate models were run for 0 to 5 day lags in each location. Among the 65+ age group, the gaseous pollutants generally exhibited stronger effects than PM_{10} or $PM_{2.5}$. The strongest overall effects were observed for SO_2 and CO. In a single pollutant model, $PM_{2.5}$ was statistically significant for lag 0 and lag 1. In co-pollutant models with CO, the $PM_{2.5}$ effect dropped out and CO remained significant.

Ages 65 and older

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[37] In a log-linear model, the percent change is equal to (RR - 1) * 100. In a similar hospitalization study by Moolgavkar (2000b), he defines and reports the "estimated" percent change as (log RR * 100). Because the relative risk is close to 1, RR-1 and log RR are essentially the same. For example, a true percent change of 0.9 would result in a relative risk of 1.009 and coefficient of 0.000896. Assuming that the 0.9 is the "estimated" percent change described previously would result in a relative risk of 1.009041 and coefficient of 0.0009. We assume that the "estimated" percent changes reported in this study reflect the definition from (Moolgavkar, 2000b).

[38] Moolgavkar (2000a) reports results that include ICD code 410 (heart attack). In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

Multipollutant Model ($PM_{2.5}$ and CO)

In a model with CO, the coefficient and standard error are calculated from an estimated percent change of 0.5[39] and t-statistic of 0.9 for a 10 $\mu g/m^3$ increase in $PM_{2.5}$ in the one day lag model (Moolgavkar, 2000a, Table 3, p. 1202).

Functional Form: Log-linear

Coefficient: 0.0005

Standard Error: 0.000556

Incidence Rate: region-specific daily hospital admission rate for all cardiovascular admissions per person 65+ (ICD codes 390-409, 411-459)[40]

Population: population of ages 65 and older

2) Lippmann et al., 2000, Detroit

Lippmann et al. (2000) studied the association between particulate matter and daily mortality and hospitalizations among the elderly in Detroit, MI. Data were analyzed for two separate study periods, 1985-1990 and 1992-1994. The 1992-1994 study period had a greater variety of data on PM size and was the main focus of the report. The authors collected hospitalization data for a variety of cardiovascular and respiratory endpoints. They used daily air quality data for PM_{10}, $PM_{2.5}$, and $PM_{10-2.5}$ in a Poisson regression model with generalized additive models (GAM) to adjust for nonlinear relationships and temporal trends. In single pollutant models, all PM metrics were statistically significant for pneumonia (ICD codes 480-486), $PM_{10-2.5}$ and PM_{10} were significant for ischemic heart disease (ICD code 410-414), and $PM_{2.5}$ and PM_{10} were significant for heart failure (ICD code 428). There were positive, but not statistically significant associations, between the PM metrics and COPD (ICD codes 490-496) and dysrhythmia (ICD code 427). In separate co-pollutant models with PM and either ozone, SO_2, NO_2, or CO, the results were generally comparable. The $PM_{2.5}$ C-R function is based on the co-pollutant model with ozone.

a) Hospital Admissions for Dysrhythmia

Multipollutant Model ($PM_{2.5}$ and ozone)

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[39] In a log-linear model, the percent change is equal to (RR - 1) * 100. In a similar hospitalization study by Moolgavkar (2000b), he defines and reports the "estimated" percent change as (log RR * 100). Because the relative risk is close to 1, RR-1 and log RR are essentially the same. For example, a true percent change of 0.5 would result in a relative risk of 1.005 and coefficient of 0.000499. Assuming that the 0.5 is the "estimated" percent change described previously would result in a relative risk of 1.005013 and coefficient of 0.0005. We assume that the "estimated" percent changes reported in this study reflect the definition from (Moolgavkar, 2000b).

[40] Moolgavkar (2000a) reports results for ICD codes 390-429. In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

The co-pollutant coefficient and standard error are calculated from a relative risk of 1.080 (95% CI 0.904-1.291) for a 36 μg/m^3 increase in $PM_{2.5}$ (Lippmann et al., 2000, Table 14, p. 27).

Functional Form: Log-linear

Coefficient: 0.002138

Standard Error: 0.002525

Incidence Rate: region-specific daily hospital admission rate for dysrhythmia admissions per person 65+ (ICD code 427)

Population: population of ages 65 and older

b) Hospital Admissions for Heart Failure

Multipollutant Model ($PM_{2.5}$ and ozone)

The co-pollutant coefficient and standard error are calculated from a relative risk of 1.183 (95% CI 1.053-1.329) for a 36 μg/m^3 increase in $PM_{2.5}$ (Lippmann et al., 2000, Table 14, p. 27).

Functional Form: Log-linear

Coefficient: 0.004668

Standard Error: 0.001650

Incidence Rate: region-specific daily hospital admission rate for heart failure admissions per person 65+ (ICD code 428)

Population: population of ages 65 and older

c) Hospital Admissions for Ischemic Heart Disease

Multipollutant Model ($PM_{2.5}$ and ozone)

The co-pollutant coefficient and standard error are calculated from a relative risk of 1.041 (95% CI 0.947-1.144) for a 36 μg/m^3 increase in $PM_{2.5}$ (Lippmann et al., 2000, Table 14, p. 27).

Functional Form: Log-linear

Coefficient: 0.001116

Standard Error: 0.001339

Incidence Rate: region-specific daily hospital admission rate for ischemic heart disease admissions per person 65+ (ICD codes 411-414)[41]

Population: population of ages 65 and older

Emergency Room Visits

There is a wealth of epidemiological information on the relationship between air pollution and hospital admissions for various respiratory and cardiovascular diseases; in addition, some studies have examined the relationship between air pollution and ER visits. Because most ER visits do not result in an admission to the hospital -- the majority of people going to the ER are treated and return home -- we treat hospital admissions and ER visits separately, taking account of the fraction of ER visits that do get admitted to the hospital, as discussed below.

The only types of ER visit that have been explicitly linked to ozone in U.S. and Canadian epidemiological studies are asthma visits. However, it seems likely that ozone may be linked to other types of respiratory-related ER visits.

Emergency Room Visits for Asthma (Norris et al., 1999)

Norris et al. (1999) examined the relation between air pollution in Seattle and childhood (<18) hospital admissions for asthma from 1995 to 1996. The authors used air quality data for PM_{10}, light scattering (used to estimate fine PM), CO, SO_2, NO_2, and O_3 in a Poisson regression model with adjustments for day of the week, time trends, temperature, and dew point. They found significant associations between asthma ER visits and light scattering (converted to $PM_{2.5}$), PM_{10}, and CO. No association was found between O_3, NO_2, or SO_2 and asthma ER visits, although O_3 had a significant amount of missing data. In multipollutant models with either PM metric (light scattering or PM_{10}) and NO_2 and SO_2, the PM coefficients remained significant while the gaseous pollutants were not associated with increased asthma ER visits. The $PM_{2.5}$ C-R function is on the multipollutant model reported.

Multipollutant Model ($PM_{2.5}$, NO_2, and SO_2)

In a model with NO_2 and SO_2, the $PM_{2.5}$ coefficient and standard error are calculated from a relative risk of 1.17 (95% CI 1.08-1.26) for a 9.5 μg/m^3 increase in $PM_{2.5}$ (Norris et al., 1999, p. 491).

Functional Form: Log-linear

Coefficient: 0.016527

Standard Error: 0.004139

[41] Lippmann et al. (2000) reports results for ICD codes 410-414. In the benefits analysis, avoided nonfatal heart attacks are estimated using the results reported by Peters et al. (2001). The baseline rate in the Peters et al. function is a modified heart attack hospitalization rate (ICD code 410), since most, if not all, nonfatal heart attacks will require hospitalization. In order to avoid double counting heart attack hospitalizations, we have excluded ICD code 410 from the baseline incidence rate used in this function.

Incidence Rate: region-specific daily emergency room rate for asthma admissions per person <18 (ICD code 493)

Population: population of ages under 18

Acute Morbidity

In addition to chronic illnesses and hospital admissions, there is a considerable body of scientific research that has estimated significant relationships between elevated air pollution levels and other morbidity health effects. Chamber study research has established relationships between specific air pollution chemicals and symptoms such as coughing, pain on deep inspiration, wheezing, eye irritation and headaches. In addition, epidemiological research has found air pollution relationships with acute infectious diseases (e.g., bronchitis, sinusitis) and a variety of "symptom-day" categories. Some "symptom-day" studies examine excess incidences of days with identified symptoms such as wheezing, coughing, or other specific upper or lower respiratory symptoms. Other studies estimate relationships for days with a more general description of days with adverse health impacts, such as "respiratory restricted activity days" or work loss days.

A challenge in preparing an analysis of the minor morbidity effects is identifying a set of effect estimates that reflects the full range of identified adverse health effects but avoids double counting. From the definitions of the specific health effects examined in each research project, it is possible to identify a set of effects that are non-overlapping, and can be ultimately treated as additive in a benefits analysis.

Acute Bronchitis (Dockery et al., 1996)

Dockery et al. (1996) examined the relationship between PM and other pollutants on the reported rates of asthma, persistent wheeze, chronic cough, and bronchitis, in a study of 13,369 children ages 8-12 living in 24 communities in U.S. and Canada. Health data were collected in 1988-1991, and single-pollutant models were used in the analysis to test a number of measures of particulate air pollution. Dockery et al. found that annual level of sulfates and particle acidity were significantly related to bronchitis, and $PM_{2.1}$ and PM_{10} were marginally significantly related to bronchitis.[42] They also found nitrates were linked to asthma, and sulfates linked to chronic phlegm. It is important to note that the study examined annual pollution exposures, and the authors did not rule out that acute (daily) exposures could be related to asthma attacks and other acute episodes.

[42] The original study measured $PM_{2.1}$, however when using the study's results we use $PM_{2.5}$. This makes only a negligible difference, assuming that the adverse effects of $PM_{2.1}$ and $PM_{2.5}$ are comparable.

Earlier work, by Dockery et al. (1989), based on six U.S. cities, found acute bronchitis and chronic cough significantly related to PM_{15}. Because it is based on a larger sample, the Dockery et al. (1996) study is the better study to develop a C-R function linking $PM_{2.5}$ with bronchitis. The C-R function to estimate the change in acute bronchitis is:

$$\Delta Acute\ Bronchitis = -\left[\frac{y_0}{(1-y_0)\cdot e^{\Delta PM_{2.5}\cdot b}+y_0} - y_0\right]\cdot pop\ ,$$

where:

y_0 = annual bronchitis incidence rate per person = 0.044

β = estimated $PM_{2.5}$ logistic regression coefficient = 0.0272

$\Delta PM_{2.5}$ = change in annual average $PM_{2.5}$ concentration

pop = population of ages 8-12

σ_β = standard error of β = 0.0171

Incidence Rate. Bronchitis was counted in the study only if there were "reports of symptoms in the past 12 months" (Dockery et al., 1996, p. 501). It is unclear, however, if the cases of bronchitis are acute and temporary, or if the bronchitis is a chronic condition. Dockery et al. found no relationship between PM and chronic cough and chronic phlegm, which are important indicators of chronic bronchitis. For this analysis, we assumed that the C-R function based on Dockery et al. is measuring acute bronchitis.

In 1994, 2,115,000 children ages 5-17 experienced acute conditions (Adams and Marano, 1995, Table 6) out of population of 48.110 million children ages 5-17 (U.S. Bureau of the Census, 1998, Table 14), or 4.4 percent of this population. This figure is somewhat lower than the 5.34 percent of children under the age of 18 reported to have chronic bronchitis in 1990-1992 (Collins, 1997, Table 8). Dockery et al. (1996, p. 503) reported that in the 24 study cities the bronchitis rate varied from three to ten percent. Finally a weighted average of the incidence rates in the six cities in the Dockery et al. (1989) study is 6.34 percent , where the sample size from each city is used to weight the respective incidence rate (Dockery et al., 1989, Tables 1 and 4).[43] This analysis assumes a 4.4 percent prevalence rate is the most representative of the national population. Note that this measure reflects the fraction of children that have a chest ailment diagnosed as bronchitis in the past year, not the number of days that children are adversely affected by acute bronchitis.[44]

[43]The unweighted average of the six city rates is 0.0647.

[44]In 1994, there were 13,707,000 restricted activity days associated with acute bronchitis, and 2,115,000 children (ages 5-17) experienced acute conditions (Adams and Marano, 1995, Tables 6 and 21). On average, then, each child with acute bronchitis suffered 6.48 days.

Coefficient Estimate (β). The estimated logistic coefficient (β) is based on the odds ratio (= 1.50) associated with being in the most polluted city ($PM_{2.1}$ = 20.7 μg/m^3) versus the least polluted city ($PM_{2.1}$ = 5.8 μg/m^3) (Dockery et al., 1996, Tables 1 and 4). The original study used $PM_{2.1}$, however, we use the $PM_{2.1}$ coefficient and apply it to $PM_{2.5}$ data.

$$\beta_{PM_{2.5}} = \frac{\ln(1.50)}{(20.7 - 5.8)} = 0.0272 .$$

Standard Error (σ_β). The standard error of the coefficient (σ_β) is calculated from the reported lower and upper bounds of the odds ratio (Dockery et al., 1996, Table 4):

$$\sigma_{\beta,high} = \frac{\beta_{high} - \beta}{1.96} = \frac{\left(\frac{\ln(2.47)}{14.9} - \frac{\ln(1.50)}{14.9}\right)}{1.96} = 0.0171$$

$$\sigma_{\beta,low} = \frac{\beta - \beta_{low}}{1.96} = \frac{\left(\frac{\ln(1.50)}{14.9} - \frac{\ln(0.91)}{14.9}\right)}{1.96} = 0.0171$$

$$\sigma_{\beta} = \frac{\sigma_{\beta,high} + \sigma_{\beta,low}}{2} = 0.0171 .$$

Lower Respiratory Symptoms (Schwartz et al., 1994)

Schwartz et al. (1994) used logistic regression to link lower respiratory symptoms in children with SO_2, NO_2, ozone, PM_{10}, $PM_{2.5}$, sulfate and H^+ (hydrogen ion). Children were selected for the study if they were exposed to indoor sources of air pollution: gas stoves and parental smoking. The study enrolled 1,844 children into a year-long study conducted in different years (1984 to 1988) in six cities. The students were in grades two through five at the time of enrollment in 1984. By the completion of the final study, the cohort would then be in the eighth grade (ages 13-14); this suggests an age range of 7 to 14.

In single pollutant models SO_2, NO_2, $PM_{2.5}$, and PM_{10} were significantly linked to cough. In two-pollutant models, PM_{10} had the most consistent relationship with cough; ozone was marginally significant, controlling for PM_{10}. In models for upper respiratory symptoms, they reported a marginally significant association for PM_{10}. In models for lower respiratory symptoms, they reported significant single-pollutant models, using SO_2, O_3, $PM_{2.5}$, PM_{10}, SO_4, and H^+.

The C-R function used to estimate the change in lower respiratory symptoms is:

$$\Delta \, Lower\,Respiratory\,Symptoms = -\left[\frac{y_0}{(1-y_0)\cdot e^{\Delta PM_{2.5}\cdot\beta} + y_0} - y_0\right]\cdot pop .$$

where:

y_0 = daily lower respiratory symptom incidence rate per person = 0.0012

β = estimated $PM_{2.5}$ logistic regression coefficient = 0.01823

$\Delta PM_{2.5}$ = change in daily average $PM_{2.5}$ concentration

pop = population of ages 7-14

σ_β = standard error of β = 0.00586

Incidence Rate. The proposed incidence rate, 0.12 percent, is based on the percentiles in Schwartz et al. (Schwartz et al., 1994, Table 2). They did not report the mean incidence rate, but rather reported various percentiles from the incidence rate distribution. The percentiles and associated values are 10^{th} = 0 percent, 25^{th} = 0 percent, 50^{th} = 0 percent, 75^{th} = 0.29 percent, and 90^{th} = 0.34 percent. The most conservative estimate consistent with the data are to assume the incidence is zero up to the 75^{th} percentile, a constant 0.29 percent between the 75^{th} and 90^{th} percentiles, and a constant 0.34 percent between the 90^{th} and 100^{th} percentiles. Alternatively, assuming a linear slope between the 50^{th} and 75^{th}, 75^{th} and 90^{th}, and 90^{th} to 100^{th} percentiles, the estimated mean incidence rate is 0.12 percent,[45] which is used in this analysis.

Coefficient Estimate (β). The coefficient β is calculated from the reported odds ratio (= 1.44) in a single-pollutant model associated with a 20 $\mu g/m^3$ change in $PM_{2.5}$ (Schwartz et al., 1994, Table 5):

$$b = \frac{\ln(1.44)}{20} = 0.01823.$$

Standard Error (σ_β). The standard error for the coefficient (σ_β) is calculated from the reported lower and upper bounds of the odds ratio (Schwartz et al., 1994, Table 5):

$$s_{b,\,high} = \frac{b_{high} - b}{1.96} = \frac{\left(\frac{\ln(1.82)}{20} - \frac{\ln(1.44)}{20}\right)}{1.96} = 0.00597$$

$$s_{b,\,low} = \frac{b - b_{low}}{1.96} = \frac{\left(\frac{\ln(1.44)}{20} - \frac{\ln(1.15)}{20}\right)}{1.96} = 0.00574$$

$$s_b = \frac{s_{b,high} + s_{b,low}}{2} = 0.00586.$$

Population. Schwartz et al. (1994, Table 5 and p. 1235) enrolled 1,844 children into a year-long study conducted in different years in different cities; the students were in grades two through five and lived in six U.S. cities. All study participants were enrolled in September 1984; the actual study was conducted in

[45]For example, the 62.5^{th} percentile would have an estimated incidence rate of 0.145 percent.

Watertown, MA in 1984/85; Kingston-Harriman, TN, and St. Louis, MO in 1985/86; Steubenville, OH, and Portage, WI in 1986/87; and Topeka, KS in 1987/88. The study does not publish the age range of the children when they participated. As a result, the study is somewhat unclear about the appropriate age range for the resulting C-R function. If all the children were in second grade in 1984 (ages 7-8) then the Topeka cohort would be in fifth grade (ages 10-11) when they participated in the study. It appears from the published description, however, that the students were in grades two through five in 1984.[46] By the completion of the study, some students in the Topeka cohort would then be in the eighth grade (ages 13-14); this suggests an age range of 7 to 14.

Upper Respiratory Symptoms (Pope et al., 1991)

Using logistic regression, Pope et al. (1991) estimated the impact of PM_{10} on the incidence of a variety of minor symptoms in 55 subjects (34 "school-based" and 21 "patient-based") living in the Utah Valley from December 1989 through March 1990. The children in the Pope et al. study were asked to record respiratory symptoms in a daily diary. With this information, the daily occurrences of upper respiratory symptoms (URS) and lower respiratory symptoms (LRS) were related to daily PM_{10} concentrations. Pope et al. describe URS as consisting of one or more of the following symptoms: runny or stuffy nose; wet cough; and burning, aching, or red eyes. Levels of ozone, NO_2, and SO_2 were reported low during this period, and were not included in the analysis. The sample in this study is relatively small and is most representative of the asthmatic population, rather than the general population. The school-based subjects (ranging in age from 9 to 11) were chosen based on "a positive response to one or more of three questions: ever wheezed without a cold, wheezed for 3 days or more out of the week for a month or longer, and/or had a doctor say the 'child has asthma' (Pope et al., 1991, p. 669)." The patient-based subjects (ranging in age from 8 to 72) were receiving treatment for asthma and were referred by local physicians. Regression results for the school-based sample (Pope et al., 1991, Table 5) show PM_{10} significantly associated with both upper and lower respiratory symptoms. The patient-based sample did not find a significant PM_{10} effect. The results from the school-based sample are used here.

Single Pollutant Model

The coefficient and standard error for a one $\mu g/m^3$ change in PM_{10} is reported in Table 5.

Functional Form: Logistic

Coefficient: 0.0036

Standard Error: 0.0015

Incidence Rate: daily upper respiratory symptom incidence rate per person = 0.3419 (Pope et al., 1991, Table 2)

Population: asthmatic population[47] ages 9 to 11 = 5.67% of population ages 9 to 11

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[46]Neas et al. (1994, p. 1091) used the same data set; their description suggests that grades two to five were represented initially.

[47] The American Lung Association (2002c, Table 7) estimates asthma prevalence for children ages 5 to 17 at 5.67% (based on data from the 1999 National Health Interview Survey).

Work Loss Days (Ostro, 1987)

Ostro (1987) estimated the impact of $PM_{2.5}$ on the incidence of work-loss days (WLDs), restricted activity days (RADs), and respiratory-related RADs (RRADs) in a national sample of the adult working population, ages 18 to 65, living in metropolitan areas. The annual national survey results used in this analysis were conducted in 1976-1981. Ostro reported that two-week average $PM_{2.5}$ levels were significantly linked to work-loss days, RADs, and RRADs, however there was some year-to-year variability in the results. Separate coefficients were developed for each year in the analysis (1976-1981); these coefficients were pooled. The coefficient used in the concentration-response function used here is a weighted average of the coefficients in Ostro (1987, Table III) using the inverse of the variance as the weight.

The study is based on a "convenience" sample of individuals ages 18-65. Applying the C-R function to this age group is likely a slight underestimate, as it seems likely that elderly are at least as susceptible to PM as individuals 65 and younger. The elderly appear more likely to die due to PM exposure than other age groups (e.g., Schwartz, 1994c, p. 30) and a number of studies have found that hospital admissions for the elderly are related to PM exposures (e.g., Schwartz, 1994a; Schwartz, 1994b). On the other hand, the number of workers over the age of 65 is relatively small; it was under 3% of the total workforce in 1996 (U.S. Bureau of the Census, 1997, Table 633).

The C-R function to estimate the change in the number of work-loss days is:

$$\Delta WLD = \Delta y \cdot pop = -\left[y_0 \cdot (e^{-b \cdot \Delta PM_{2.5}} - 1)\right] \cdot pop,$$

where:

y_0 = daily work-loss-day incidence rate per person = 0.00648

β = inverse-variance weighted $PM_{2.5}$ coefficient = 0.0046

$\Delta PM_{2.5}$ = change in daily average $PM_{2.5}$ concentration[48]

pop = population of ages 18 to 65

σ_β = standard error of β = 0.00036

Incidence Rate. The estimated 1994 annual incidence rate is the annual number (376,844,000) of WLD per person in the age 18-64 population divided by the number of people in 18-64 population (159,361,000). The

[48]The study used a two-week average pollution concentration; the daily rate used here is assumed to be a reasonable approximation.

1994 daily incidence rate is calculated as the annual rate divided by 365.[49] Data are from U.S. Bureau of the Census (1997, Table 14) and Adams (1995, Table 41).

Coefficient Estimate (β). The coefficient used in the C-R function is a weighted average of the coefficients in Ostro (1987, Table III) using the inverse of the variance as the weight:

$$b = \left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{\sum_{i=1976}^{1981} \frac{1}{s_{b_i}^2}} \right) = 0.0046 .$$

Standard Error (σ_β). The standard error of the coefficient (σ_β) is calculated as follows, assuming that the estimated year-specific coefficients are independent:

$$s_b^2 = \mathrm{var}\left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{\sum_{i=1976}^{1981} \frac{1}{s_{b_i}^2}} \right) = \left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{g} \right) = \sum_{i=1976}^{1981} \mathrm{var}\left(\frac{b_i}{s_{b_i}^2 \cdot g} \right) .$$

This eventually reduces down to:

$$s_b^2 = \frac{1}{g} \Rightarrow s_b = \sqrt{\frac{1}{g}} = 0.00036.$$

Minor Restricted Activity Days (Ostro and Rothschild, 1989)

Ostro and Rothschild (1989) estimated the impact of $PM_{2.5}$ on the incidence of minor restricted activity days (MRADs) and respiratory-related restricted activity days (RRADs) in a national sample of the adult working population, ages 18 to 65, living in metropolitan areas. The annual national survey results used in this analysis were conducted in 1976-1981. Controlling for $PM_{2.5}$, two-week average O_3 has highly variable association with RRADs and MRADs. Controlling for O_3, two-week average $PM_{2.5}$ was significantly linked to both health endpoints in most years.

The study is based on a "convenience" sample of individuals ages 18-65. Applying the C-R function to this age group is likely a slight underestimate, as it seems likely that elderly are at least as susceptible to PM as individuals 65 and younger. The elderly appear more likely to die due to PM exposure than other age

[49]Ostro (1987) analyzed a sample aged 18 to 65. It is assumed that the age 18-64 rate is a reasonably good approximation to the rate for individuals 18-65. Data are from U.S. Bureau of the Census (1997, Table 14) and Adams (1995, Table 41).

groups (e.g., Schwartz, 1994c, p. 30) and a number of studies have found that hospital admissions for the elderly are related to PM exposures (e.g., Schwartz, 1994a; Schwartz, 1994b).

Using the results of the two-pollutant model, we developed separate coefficients for each year in the analysis, which were then combined for use in this analysis. The coefficient used in this analysis is a weighted average of the coefficients (Ostro, 1987, Table IV) using the inverse of the variance as the weight. The C-R function to estimate the change in the number of minor restricted activity days (MRAD) is:

$$\Delta MRAD = \Delta y \cdot pop = -\left[y_0 \cdot (e^{-b \cdot \Delta PM_{2.5}} - 1) \right] \cdot pop,$$

where:

y_0 = daily MRAD daily incidence rate per person = 0.02137

β = inverse-variance weighted $PM_{2.5}$ coeffcient = 0.00741

$\Delta PM_{2.5}$ = change in daily average $PM_{2.5}$ concentration[50]

pop = adult population ages 18 to 65

σ_β = standard error of β = 0.0007

Incidence Rate. The annual incidence rate (7.8) provided by Ostro and Rothschild (1989, p. 243) was divided by 365 to get a daily rate of 0.02137.

Coefficient Estimate (β). The coefficient is a weighted average of the coefficients in Ostro and Rothschild (1989, Table 4) using the inverse of the variance as the weight:

$$b = \left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{\sum_{i=1976}^{1981} \frac{1}{s_{b_i}^2}} \right) = 0.00741.$$

[50]The study used a two-week average pollution concentration; the daily rate used here is assumed to be a reasonable approximation.

Standard Error (σ_β). The standard error of the coefficient (σ_β) is calculated as follows, assuming that the estimated year-specific coefficients are independent:

$$s_b^2 = \mathrm{var}\left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{\sum_{i=1976}^{1981} \frac{1}{s_{b_i}^2}}\right) = \left(\frac{\sum_{i=1976}^{1981} \frac{b_i}{s_{b_i}^2}}{g}\right) = \sum_{i=1976}^{1981} \mathrm{var}\left(\frac{b_i}{s_{b_i}^2 \cdot g}\right).$$

This reduces down to:

$$s_b^2 = \frac{1}{g} \Rightarrow s_b = \sqrt{\frac{1}{g}} = 0.00070.$$

Supplemental Concentration Response Functions

Mortality (Krewski et al., 2000) - Reanalysis of Dockery et al. (1993)

Krewski et al. (2000) performed a validation and replication analysis of Dockery et al. (1993). The original investigators examined the relationship between PM exposure and mortality in a cohort of 8,111 individuals aged 25 and older, living in six U.S. cities. They surveyed these individuals in 1974-1977 and followed their health status until 1991. While they used a smaller sample of individuals from fewer cities than the study by Pope et al., they used improved exposure estimates, a slightly broader study population (adults aged 25 and older; a higher proportion without a high school education), and a follow-up period nearly twice as long as that of Pope et al. (1995). Krewski et al. (2000, Part II - Table 52) found that educational status was a strong effect modifier of the PM - mortality relationship in both studies, with the strongest effect seen among the less educated. Perhaps because of these differences, Dockery et al. study found a larger effect of PM on premature mortality than that found by Pope et al.

After an audit of the air pollution data, demographic variables, and cohort selection process, Krewski et al. (2000) noted that a small portion of study participants were mistakenly censored early. The following C-R function is based on the risk estimate from the audited data, with the inclusion of those person-years mistakenly censored early.

Single Pollutant Model

The coefficient and standard error are estimated from the relative risk (1.28) and 95% confidence interval (1.10-1.48) associated with a change in *annual mean* $PM_{2.5}$ exposure of 18.6 $\mu g/m^3$ to 29.6 $\mu g/m^3$ (Krewski et al., 2000, Part I - Table 19c).

Functional Form: Log-linear

Coefficient: 0.013272

Standard Error: 0.004070

Incidence Rate: county-specific annual all cause mortality rate per person ages 25 and older

Population: population of ages 25 and older

Mortality, Lung Cancer (Pope et al., 2002) - Based on ACS Cohort: Mean $PM_{2.5}$

Pope et al. (2002) followed Krewski et al. (2000) and Pope et al. (1995, Table 2) and reported results for all-cause deaths, lung cancer (ICD-9 code: 162), cardiopulmonary deaths (ICD-9 codes: 401-440 and 460-519), and "all other" deaths.[51] Like the earlier studies, Pope et al. (2002) found that mean $PM_{2.5}$ is significantly related to all-cause and cardiopulmonary mortality. In addition, Pope et al. (2002) found a significant relationship with lung cancer mortality, which was not found in the earlier studies. None of the three studies found a significant relationship with "all other" deaths.

'79-'83 Exposure

The coefficient and standard error for $PM_{2.5}$ using the '79-'83 PM data are estimated from the relative risk (1.082) and 95% confidence interval (1.011-1.158) associated with a change in *annual mean* exposure of 10.0 $\mu g/m^3$. Pope et al. (2002, Table 2).[52]

Functional Form: Log-linear

Coefficient: 0.007881

Standard Error: 0.003463

Incidence Rate: county-specific annual lung cancer mortality rate (ICD code 162) per person ages 30 and older

Population: population of ages 30 and older

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[51] All-cause mortality includes accidents, suicides, homicides and legal interventions. The category "all other" deaths is all-cause mortality less lung cancer and cardiopulmonary deaths.

[52] Note that we used an unpublished, final version of the paper that presents the relative risks with one more significant digit than that found in the published version. We chose to use this extra information to increase the precision of our estimates.

Appendix B: Benefits Estimate: Uncertainty Results

Uncertainty estimates (5th and 95th percentile estimates) for the health and valuation results are shown in Tables B-1 through B-4.

Table B-1 2010 Health Benefits with Uncertainty: Numbers of Avoided Cases

	CSA	No EGU			Carper		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	7,861	13,527	23,604	33,632	5,969	10,430	14,880
Chronic Bronchitis	5,400	3,025	16,221	29,069	1,326	7,160	12,921
Heart Attacks	13,115	14,377	38,198	60,841	6,401	17,218	27,753
Hospital Admissions-Respiratory							
Chronic Lung, less Asthma(20-64)	374	284	1,127	1,975	125	496	868
Asthma (0-64)	651	610	1,946	3,291	270	860	1,453
Pneumonia (65+)	2,653	2,364	8,040	13,780	1,036	3,515	6,008
Chronic Lung (65+)	332	(1,464)	1,000	3,641	(647)	441	1,602
Total Hospital Admissions-Respiratory	4,010		12,113			5,313	
Hospital Admissions Cardiovascular							
All Cardiovascular,(20-64)	1,332	347	4,028	7,719	153	1,778	3,406
All Cardiovascular,(65+)	1,903	(2,547)	5,707	18,651	(1,126)	2,521	8,207
Total Hospital Admissions-Cardiovascular	3,235		9,735			4,299	
Emergency Room Visits for Asthma	8,316	15,103	25,999	37,163	6,493	11,108	15,779
Acute Bronchitis	12,522	(1,297)	37,705	74,385	(562)	16,614	33,303
Lower Respiratory Symptoms	142,621	206,086	429,980	646,906	89,990	189,214	286,836
Upper Respiratory Symptoms	113,707	109,901	348,823	587,102	47,666	151,390	254,973
Work Loss Days	1,050,415	2,778,689	3,186,036	3,592,565	1,216,135	1,395,098	1,573,877
Minor Restricted Activity Days	6,258,491	16,008,538	18,916,818	21,813,846	7,022,655	8,306,310	9,587,433

Table B-1 2010 Health Benefits with Uncertainty: Numbers of Avoided Cases (continued)

	CSA	Straw			Jeffords		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	7,861	6,353	11,100	15,836	9,492	16,575	23,634
Chronic Bronchitis	5,400	1,411	7,615	13,737	2,118	11,397	20,500
Heart Attacks	13,115	6,786	18,244	29,394	10,110	27,039	43,342
Hospital Admissions - Respiratory							
Chronic Lung, less Asthma (20-64)	374	133	527	922	199	791	1,386
Asthma (0-64)	651	286	912	1,540	427	1,362	2,301
Pneumonia (65+)	2,653	1,100	3,733	6,381	1,657	5,628	9,632
Chronic Lung (65+)	332	(687)	468	1,702	(1,029)	702	2,554
Total Hospital Admissions - Respiratory	4,010		5,640			8,484	
Hospital Admissions Cardiovascular							
All Cardiovascular, (20-64)	1,332	163	1,893	3,625	244	2,829	5,420
All Cardiovascular, (65+)	1,903	(1,195)	2,677	8,712	(1,787)	4,006	13,064
Total Hospital Admissions - Cardiovascular	3,235		4,570			6,835	
Emergency Room Visits for Asthma	8,316	6,901	11,811	16,782	10,610	18,205	25,936
Acute Bronchitis	12,522	(598)	17,669	35,393	(905)	26,554	52,826
Lower Respiratory Symptoms	142,621	95,720	201,197	304,907	144,480	302,678	457,198
Upper Respiratory Symptoms	113,707	50,715	161,069	271,268	76,773	243,760	410,415
Work Loss Days	1,050,415	1,293,454	1,483,765	1,673,875	1,945,445	2,231,223	2,516,574
Minor Restricted Activity Days	6,258,491	7,468,187	8,832,956	10,194,911	11,220,404	13,265,510	15,304,720

Table B-2 Value of 2010 Health Benefits with Uncertainty (Millions of $1999)

	CSA	No EGU			Carper		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	$51,974	$21,838	$149,274	$359,554	$9,645	$65,959	$158,961
Chronic Bronchitis	$2,046	$466	$5,523	$18,709	$204	$2,438	$8,262
Heart Attacks	$1,127	$950	$3,284	$7,573	$425	$1,480	$3,447
Hospital Admissions - Respiratory							
Chronic Lung, less Asthma (20-64)	$4	$3	$13	$24	$2	$6	$11
Asthma (0-64)	$5	$5	$15	$25	$2	$7	$10
Pneumonia (65+)	$47	$41	$143	$237	$18	$63	$104
Chronic Lung (65+)	$4	-$18	$13	$47	-$8	$6	$21
Total Hospital Admissions - Respiratory	$60		$187			$82	
Hospital Admissions Cardiovascular							
All Cardiovascular, (20-64)	$30	$8	$92	$169	$3	$41	$75
All Cardiovascular, (65+)	$39	-$64	$116	$335	-$28	$51	$147
Total Hospital Admissions - Cardiovascular	$69		$206			$92	
Emergency Room Visits for Asthma	$2	$4	$7	$11	$2	$3	$5
Acute Bronchitis	$5	$0	$13	$33	$0	$6	$14
Lower Respiratory Symptoms	$2	$3	$7	$12	$1	$3	$6
Upper Respiratory Symptoms	$3	$3	$9	$19	$1	$4	$7
Work Loss Days	$136	$338	$367	$437	$148	$161	$191
Minor Restricted Activity Days	$327	$549	$956	$1,340	$241	$420	$589

Table B-2 Value of 2010 Health Benefits with Uncertainty (Millions of $1999) (Continued)

	CSA	Straw			Jeffords		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	$51,974	$10,265	$70,198	$169,171	$15,331	$104,823	$252,558
Chronic Bronchitis	$2,046	$217	$2,592	$8,786	$326	$3,881	$13,148
Heart Attacks	$1,127	$450	$1,568	$3,651	$670	$2,324	$5,389
Hospital Admissions - Respiratory							
Chronic Lung, less Asthma (20-64)	$4	$2	$6	$11	$2	$9	$17
Asthma (0-64)	$5	$2	$7	$11	$3	$11	$17
Pneumonia (65+)	$47	$19	$67	$110	$29	$100	$166
Chronic Lung (65+)	$4	-$8	$6	$22	-$13	$9	$33
Total Hospital Admissions - Respiratory	$60		$87			$132	
Hospital Admissions Cardiovascular							
All Cardiovascular, (20-64)	$30	$4	$43	$80	$6	$64	$119
All Cardiovascular, (65+)	$39	-$30	$54	$156	-$45	$81	$234
Total Hospital Admissions - Cardiovascular	$69		$97			$146	
Emergency Room Visits for Asthma	$2	$2	$3	$5	$3	$5	$8
Acute Bronchitis	$5	$0	$7	$15	$0	$10	$23
Lower Respiratory Symptoms	$2	$1	$3	$6	$2	$5	$8
Upper Respiratory Symptoms	$3	$1	$4	$8	$2	$6	$13
Work Loss Days	$136	$158	$171	$204	$237	$257	$306
Minor Restricted Activity Days	$327	$257	$447	$626	$385	$670	$940

Table B-3 2020 Health Benefits with Uncertainty: Numbers of Avoided Cases

	CSA	Carper			Straw		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	14,104	9,255	16,166	23,057	10,510	18,355	26,174
Chronic Bronchitis	8,770	1,864	10,048	18,105	2,121	11,422	20,560
Heart Attacks	23,009	9,795	26,280	42,253	11,126	29,798	47,827
Hospital Admissions - Respiratory							
Chronic Lung, less Asthma (20-64)	610	176	699	1,223	200	794	1,390
Asthma (0-64)	1,151	359	1,145	1,934	408	1,302	2,199
Pneumonia (65+)	4,972	1,681	5,705	9,756	1,913	6,496	11,114
Chronic Lung (65+)	650	(1,093)	746	2,711	(1,242)	848	3,083
Total Hospital Admissions - Respiratory	7,383		8,295			7,513	
Hospital Admissions Cardiovascular							
All Cardiovascular, (20-64)	2,139	211	2,452	4,697	240	2,782	5,329
All Cardiovascular, (65+)	3,632	(1,868)	4,165	13,712	(2,141)	4,731	15,381
Total Hospital Admissions - Cardiovascular	5,771		6,617			7,513	
Emergency Room Visits for Asthma	13,223	8,867	15,191	21,608	10,132	17,373	24,734
Acute Bronchitis	19,919	(775)	22,823	45,580	(884)	25,971	51,755
Lower Respiratory Symptoms	226,616	123,702	259,649	392,945	140,932	295,492	446,707
Upper Respiratory Symptoms	181,286	65,533	208,106	350,443	74,731	237,294	399,557
Work Loss Days	1,602,343	1,601,815	1,837,341	2,072,576	1,823,365	2,091,325	2,358,915
Minor Restricted Activity Days	9,519,433	9,226,638	10,910,946	12,591,232	10,498,482	12,413,325	14,323,062

Table B-3 2010 Health Benefits with Uncertainty: Numbers of Avoided Cases (Continued)

	CSA	Jeffords		
	Mean	5th Percentile	Mean	95th Percentile
Mortality	14,104	12,456	21,749	31,006
Chronic Bronchitis	8,770	2,526	13,586	24,421
Heart Attacks	23,009	13,185	35,230	56,418
Hospital Admissions - Respiratory				
Chronic Lung, less Asthma (20-64)	610	238	945	1,655
Asthma (0-64)	1,151	484	1,545	2,610
Pneumonia (65+)	4,972	2,281	7,749	13,264
Chronic Lung (65+)	650	(1,477)	1,008	3,667
Total Hospital Admissions - Respiratory	7,383		11,247	
Hospital Admissions Cardiovascular				
All Cardiovascular, (20-64)	2,139	284	3,296	6,314
All Cardiovascular, (65+)	3,632	(2,537)	5,615	18,273
Total Hospital Admissions - Cardiovascular	5,771		8,911	
Emergency Room Visits for Asthma	13,223	12,263	21,050	30,005
Acute Bronchitis	19,919	(1,059)	31,013	61,598
Lower Respiratory Symptoms	226,616	168,653	353,091	533,005
Upper Respiratory Symptoms	181,286	89,544	284,295	478,639
Work Loss Days	1,602,343	2,176,116	2,495,685	2,814,756
Minor Restricted Activity Days	9,519,433	12,519,823	14,800,704	17,074,718

Table B-4 Value of 2020 Health Benefits with Uncertainty (Millions of $1999)

	CSA	Carper			Straw		
	Mean	5th Percentile	Mean	95th Percentile	5th Percentile	Mean	95th Percentile
Mortality	$106,996	$17,154	$117,302	$282,662	$19,478	$133,186	$320,915
Chronic Bronchitis	$3,880	$335	$3,995	$13,536	$381	$4,540	$15,386
Heart Attacks	$1,961	$638	$2,240	$5,221	$724	$2,540	$5,912
Hospital Admissions - Respiratory							
Chronic Lung, less Asthma (20-64)	$7	$2	$8	$15	$2	$9	$17
Asthma (0-64)	$9	$3	$9	$14	$3	$10	$16
Pneumonia (65+)	$89	$29	$102	$168	$33	$116	$191
Chronic Lung (65+)	$9	-$14	$10	$36	-$15	$11	$40
Total Hospital Admissions - Respiratory	$114		$131			$149	
Hospital Admissions Cardiovascular							
All Cardiovascular, (20-64)	$49	$5	$56	$103	$5	$63	$117
All Cardiovascular, (65+)	$74	-$47	$84	$244	-$54	$96	$277
Total Hospital Admissions - Cardiovascular	$123		$140			$159	
Emergency Room Visits for Asthma	$4	$2	$4	$7	$3	$5	$7
Acute Bronchitis	$8	$0	$9	$20	$0	$10	$23
Lower Respiratory Symptoms	$4	$2	$4	$7	$2	$5	$8
Upper Respiratory Symptoms	$5	$2	$6	$11	$2	$6	$13
Work Loss Days	$208	$195	$212	$252	$222	$241	$287
Minor Restricted Activity Days	$522	$333	$578	$811	$378	$658	$923

Table B-4 Value of 2020 Health Benefits with Uncertainty (Millions of $1999) (Continued)

	CSA 2020	Jeffords		
	Mean	5th Percentile	Mean	95th Percentile
Mortality	$106,996	$23,083	$157,813	$380,215
Chronic Bronchitis	$3,880	$455	$5,401	$18,299
Heart Attacks	$1,961	$859	$3,003	$6,977
Hospital Admissions - Respiratory				
Chronic Lung, less Asthma (20-64)	$7	$3	$11	$20
Asthma (0-64)	$9	$4	$12	$19
Pneumonia (65+)	$89	$40	$138	$229
Chronic Lung (65+)	$9	-$18	$14	$47
Total Hospital Admissions - Respiratory	$114		$177	
Hospital Admissions Cardiovascular				
All Cardiovascular, (20-64)	$49	$6	$75	$139
All Cardiovascular, (65+)	$74	-$63	$114	$330
Total Hospital Admissions - Cardiovascular	$123		$188	
Emergency Room Visits for Asthma	$4	$3	$6	$9
Acute Bronchitis	$8	$0	$12	$28
Lower Respiratory Symptoms	$4	$2	$6	$10
Upper Respiratory Symptoms	$5	$2	$8	$16
Work Loss Days	$208	$265	$288	$342
Minor Restricted Activity Days	$522	$451	$784	$1,100

Appendix C: Details of SMAT Non-Attainment Analysis

Table C-1 reports the estimated design values for the 307 counties included in the EPA Clear Skies Act SMAT analysis. Table C-1 includes the EPA estimates of the observed monitors (1999-2001) and of the Clear Skies Act, as well as the estimates for all the policy options included in this report.

Table C-1 County Estimates of PM2.5 Design Values

State	County	'99-'01 EPA CSA Analysis PM2.5 1999-2001 Ambient Design Value	2010 PM2.5 Base case 2010	2010 PM2.5 Clear Skies 2010	2010 Jeffords	2010 Straw	2010 Carper	2010 No EGU	2020 EPA CSA Analysis PM2.5 Base case 2020	2020 PM2.5 Clear Skies 2020	2020 Jeffords	2020 Straw	2020 Carper
Total National Number of Non-Attaining Counties		129	80	38	16	24	27	13	53	18	13	13	15
Alabama	Clay	15.55	14.27	13.31	11.71	12.50	12.70	10.76	13.59	11.87	11.07	11.31	10.47
Alabama	Colbert	15.25	13.46	12.21	10.74	11.47	11.65	9.87	12.74	10.87	10.14	10.36	9.59
Alabama	DeKalb	16.76	15.24	14.09	11.95	13.02	13.22	10.75	14.40	12.34	11.25	11.25	11.62
Alabama	Houston	16.33	15.19	14.18	12.47	13.32	13.53	11.46	14.84	13.09	12.20	12.47	11.54
Alabama	Jefferson	21.58	20.07	18.96	17.15	18.13	18.32	15.96	19.22	17.38	16.35	16.35	16.60
Alabama	Madison	15.50	13.97	12.79	10.95	11.98	12.15	9.85	13.19	11.33	10.30	10.30	10.66
Alabama	Mobile	15.34	14.45	13.62	12.45	13.11	13.26	11.61	14.40	12.93	12.39	12.39	12.63
Alabama	Montgomery	16.79	15.71	14.74	13.06	13.89	14.15	12.06	15.31	13.63	12.74	12.74	12.95
Alabama	Morgan	19.30	17.74	16.24	14.28	15.26	15.50	13.12	16.82	14.46	13.48	13.78	12.75
Alabama	Russell	18.39	17.11	15.93	14.06	14.96	15.23	12.87	16.48	14.36	13.43	13.43	13.67
Alabama	Shelby	16.58	15.32	14.44	13.03	13.82	14.00	12.10	14.70	13.20	12.43	12.43	12.68
Alabama	Talladega	17.76	16.42	15.53	13.54	14.41	14.79	12.42	15.85	14.16	13.14	13.14	13.37
Arizona	Coconino	7.50	7.20	7.16	7.13	7.14	7.15	7.11	7.12	7.07	7.01	7.03	7.05
Arizona	Gila	9.60	9.11	9.05	9.02	9.03	9.04	9.00	9.01	8.93	8.87	8.89	8.91
Arizona	Maricopa	11.20	10.78	10.72	10.69	10.70	10.71	10.67	10.79	10.71	10.65	10.67	10.69
Arizona	Pinal	8.60	8.30	8.23	8.20	8.21	8.22	8.18	8.30	8.22	8.16	8.18	8.20
Arizona	Santa Cruz	12.10	11.70	11.58	11.55	11.56	11.57	11.53	11.71	11.55	11.49	11.51	11.53
California	Alameda	12.20	11.22	11.21	11.18	11.19	11.20	11.16	10.53	10.52	10.46	10.48	10.50
California	Butte	15.40	14.03	14.01	13.98	13.99	14.00	13.96	13.33	13.31	13.25	13.27	13.29
California	Calaveras	9.40	8.39	8.38	8.35	8.36	8.37	8.33	7.80	7.79	7.73	7.75	7.77
California	Colusa	10.30	9.55	9.54	9.51	9.52	9.53	9.49	9.18	9.17	9.11	9.13	9.15
California	El Dorado	8.10	7.34	7.33	7.30	7.31	7.32	7.28	6.93	6.91	6.85	6.87	6.89
California	Fresno	24.00	21.76	21.73	21.70	21.71	21.72	21.68	20.85	20.82	20.76	20.78	20.80
California	Humboldt	9.20	8.58	8.58	8.55	8.56	8.57	8.53	8.56	8.55	8.49	8.51	8.53
California	Imperial	15.70	13.83	13.75	13.72	13.73	13.74	13.70	13.38	13.28	13.22	13.24	13.26
California	Kern	23.70	20.68	20.64	20.61	20.62	20.63	20.59	19.62	19.58	19.52	19.54	19.56
California	Kings	16.60	14.29	14.26	14.23	14.24	14.25	14.21	13.16	13.13	13.07	13.09	13.11
California	Los Angeles	25.90	23.73	23.69	23.66	23.67	23.68	23.64	23.84	23.80	23.74	23.76	23.78
California	Mendocino	8.00	7.21	7.20	7.17	7.18	7.19	7.15	6.85	6.84	6.78	6.80	6.82
California	Merced	18.90	16.51	16.48	16.45	16.46	16.47	16.43	15.20	15.17	15.11	15.13	15.15
California	Modoc	8.00	7.42	7.41	7.38	7.39	7.40	7.36	7.13	7.11	7.05	7.07	7.09

State	County	'99-'01 *EPA CSA Analysis* PM2.5 1999-2001 Ambient Design Value	2010 PM2.5 Base case 2010	2010 PM2.5 Clear Skies 2010	2010 Jeffords	2010 Straw	2010 Carper	2010 No EGU	2020 *EPA CSA Analysis* PM2.5 Base case 2020	2020 PM2.5 Clear Skies 2020	2020 Jeffords	2020 Straw	2020 Carper
California	Orange	22.40	20.76	20.71	20.68	20.69	20.70	20.66	21.16	21.10	21.04	21.06	21.08
California	Placer	12.50	11.29	11.28	11.25	11.26	11.27	11.23	10.72	10.71	10.65	10.67	10.69
California	Riverside	29.80	27.98	27.92	27.89	27.90	27.91	27.87	27.94	27.87	27.81	27.83	27.85
California	San Bernardino	25.80	24.22	24.18	24.15	24.16	24.17	24.13	24.19	24.13	24.07	24.09	24.11
California	San Diego	17.10	16.00	15.97	15.94	15.95	15.96	15.92	16.30	16.26	16.20	16.22	16.24
California	San Joaquin	16.40	14.78	14.76	14.73	14.74	14.75	14.71	13.89	13.87	13.81	13.83	13.85
California	San Luis Obispo	10.00	9.16	9.15	9.12	9.13	9.14	9.10	8.92	8.90	8.84	8.86	8.88
California	Shasta	10.40	9.45	9.44	9.41	9.42	9.43	9.39	9.07	9.06	9.00	9.02	9.04
California	Sonoma	11.10	9.91	9.90	9.87	9.88	9.89	9.85	9.40	9.39	9.33	9.35	9.37
California	Stanislaus	19.70	17.39	17.37	17.34	17.35	17.36	17.32	16.05	16.03	15.97	15.99	16.01
California	Sutter	12.90	11.87	11.86	11.83	11.84	11.85	11.81	11.34	11.32	11.26	11.28	11.30
California	Tulare	24.70	22.18	22.15	22.12	22.13	22.14	22.10	21.23	21.20	21.14	21.16	21.18
California	Ventura	14.50	13.71	13.69	13.66	13.67	13.68	13.64	13.85	13.82	13.76	13.78	13.80
Colorado	Boulder	9.20	8.79	8.65	8.62	8.63	8.64	8.60	8.79	8.61	8.55	8.57	8.59
Colorado	Mesa	7.30	6.80	6.66	6.63	6.64	6.65	6.61	6.68	6.51	6.45	6.47	6.49
Connecticut	Fairfield	13.59	12.53	11.75	11.19	11.57	11.61	10.66	12.07	10.99	10.65	10.65	10.74
Connecticut	New Haven	16.81	15.47	14.57	14.00	14.42	14.46	13.41	14.99	13.73	13.42	13.42	13.54
Delaware	Kent	12.90	11.89	10.70	9.89	10.41	10.49	9.04	11.21	9.56	9.20	9.20	9.36
Delaware	New Castle	16.62	15.49	14.26	13.35	13.86	13.94	12.48	14.80	13.09	12.49	12.49	12.65
Delaware	Sussex	14.48	13.34	11.99	10.76	11.44	11.53	9.75	12.65	10.78	10.06	10.06	10.22
D.C.	District of Columl	16.56	15.48	13.90	12.84	13.39	13.48	11.72	14.65	12.53	11.93	12.08	11.08
Florida	Alachua	10.86	9.87	9.10	8.10	8.54	8.64	7.40	9.53	8.34	7.69	7.69	7.77
Florida	Broward	9.04	8.37	7.91	7.76	7.99	8.02	7.44	8.26	7.55	7.59	7.59	7.64
Florida	Citrus	10.54	9.46	8.54	7.67	8.04	8.23	6.83	9.18	7.80	7.48	7.48	7.44
Florida	Escambia	13.38	12.38	11.52	9.91	10.72	10.88	9.13	12.03	10.47	9.64	9.64	9.97
Florida	Hillsborough	12.65	11.01	10.38	9.73	10.08	10.17	9.09	10.70	9.63	9.31	9.31	9.40
Florida	Lee	9.63	8.53	7.98	7.49	7.80	7.84	6.99	8.21	7.33	7.08	7.08	7.16
Florida	Leon	13.36	12.18	11.27	10.36	10.79	10.88	9.63	11.75	10.19	9.90	10.01	9.15
Florida	Miami-Dade	8.48	7.67	7.23	7.27	7.46	7.49	6.99	7.54	6.83	7.08	7.08	7.13
Florida	Orange	11.36	10.27	9.58	8.89	9.29	9.35	8.12	9.91	8.82	8.37	8.37	8.53
Florida	Pinellas	11.83	10.30	9.70	9.14	9.46	9.54	8.54	10.02	9.01	8.74	8.74	8.83
Florida	St. Lucie	9.56	8.52	7.96	7.66	7.91	7.90	7.10	8.23	7.32	7.22	7.22	7.25
Florida	Sarasota	10.52	9.18	8.60	8.20	8.50	8.56	7.67	8.87	7.91	7.77	7.77	7.85
Florida	Seminole	10.50	9.30	8.63	8.03	8.38	8.45	7.37	8.90	7.84	7.50	7.50	7.61
Florida	Volusia	10.62	9.53	8.82	8.22	8.59	8.66	7.56	9.12	8.00	7.69	7.69	7.80
Georgia	Bibb	17.63	16.42	15.28	13.20	14.16	14.40	12.10	15.93	13.83	12.86	13.15	11.83

State	County	'99-'01 *EPA CSA Analysis* PM2.5 1999-2001 Ambient Design Value	2010 PM2.5 Base case 2010	2010 PM2.5 Clear Skies 2010	2010 Jeffords	2010 Straw	2010 Carper	2010 No EGU	2020 *EPA CSA Analysis* PM2.5 Base case 2020	2020 PM2.5 Clear Skies 2020	2020 Jeffords	2020 Straw	2020 Carper
Georgia	Chatham	16.50	15.63	14.55	12.57	13.48	13.71	11.53	15.65	13.75	12.78	13.07	11.77
Georgia	Clarke	18.62	17.10	15.76	13.43	14.51	14.86	12.21	16.08	13.53	12.53	12.53	12.85
Georgia	Clayton	19.16	17.79	16.64	14.47	15.44	15.68	13.34	16.82	14.58	13.61	13.61	13.89
Georgia	Cobb	18.56	16.84	15.80	13.39	14.39	14.59	12.19	15.88	13.55	12.53	12.53	12.88
Georgia	DeKalb	19.56	18.31	17.11	14.89	15.95	16.18	13.79	17.65	15.40	14.37	14.37	14.66
Georgia	Dougherty	16.61	15.69	14.66	12.67	13.59	13.82	11.61	15.37	13.39	12.45	12.74	11.46
Georgia	Floyd	18.46	17.01	15.79	13.61	14.67	14.90	12.42	16.25	14.00	12.98	12.98	13.33
Georgia	Fulton	21.21	19.85	18.58	16.21	17.34	17.59	15.05	19.13	16.75	15.65	15.65	15.95
Georgia	Hall	17.25	15.68	14.43	12.21	13.19	13.39	11.02	14.66	12.31	11.32	11.32	11.63
Georgia	Muscogee	17.98	16.73	15.57	13.74	14.62	14.89	12.57	16.11	14.03	13.13	13.13	13.36
Georgia	Paulding	16.77	15.43	14.31	12.36	13.33	13.56	11.28	14.67	12.65	11.70	11.70	12.00
Georgia	Richmond	17.12	16.04	14.78	12.70	13.59	13.88	11.62	15.27	13.06	12.01	12.01	12.28
Georgia	Washington	16.47	15.41	14.31	12.37	13.26	13.49	11.34	14.89	12.90	12.00	12.27	11.05
Georgia	Wilkinson	17.76	16.73	15.68	13.98	14.81	15.07	12.97	16.25	14.21	13.50	13.50	13.76
Idaho	Ada	9.50	8.59	8.58	8.55	8.56	8.57	8.53	8.21	8.19	8.13	8.15	8.17
Idaho	Bannock	10.00	9.25	9.21	9.18	9.19	9.20	9.16	9.06	9.01	8.95	8.97	8.99
Idaho	Canyon	10.20	9.07	9.06	9.03	9.04	9.05	9.01	8.91	8.89	8.83	8.85	8.87
Idaho	Twin Falls	3.20	2.99	2.98	2.95	2.96	2.97	2.93	2.90	2.88	2.82	2.84	2.86
Illinois	Champaign	13.79	13.03	11.78	10.47	11.44	11.48	9.45	12.34	10.67	9.64	9.64	10.15
Illinois	Cook	18.79	17.98	16.90	15.67	16.58	16.61	14.74	17.44	15.94	14.73	14.73	15.36
Illinois	DuPage	15.45	14.79	13.81	12.63	13.53	13.55	11.76	14.18	12.83	11.73	11.73	12.34
Illinois	Madison	17.27	16.32	15.19	13.72	14.76	14.80	12.75	15.71	14.14	12.86	12.86	13.46
Illinois	Randolph	13.91	12.75	11.38	10.32	11.12	11.15	9.54	11.95	10.40	9.46	9.94	9.43
Illinois	St. Clair	17.43	16.39	15.10	13.59	14.67	14.72	12.59	15.74	14.01	12.71	12.71	13.30
Illinois	Sangamon	14.16	13.06	11.93	10.64	11.58	11.62	9.70	12.38	10.90	9.81	9.81	10.33
Illinois	Will	15.87	15.26	14.23	12.92	13.94	13.96	12.02	14.73	13.32	12.11	12.11	12.81
Indiana	Clark	17.34	15.95	14.37	12.62	13.70	13.83	11.15	15.29	13.06	11.89	11.89	12.34
Indiana	Floyd	15.60	14.34	12.89	11.30	12.29	12.41	9.96	13.74	11.71	10.65	10.65	11.06
Indiana	Lake	16.26	15.49	14.49	13.31	14.17	14.22	12.43	14.85	13.47	12.40	12.40	12.98
Indiana	Marion	17.01	15.97	14.45	12.94	13.91	14.01	11.73	15.13	13.19	12.01	12.01	12.45
Indiana	Porter	13.93	13.26	12.41	11.39	12.14	12.17	10.62	12.71	11.53	10.61	10.61	11.11
Iowa	Black Hawk	11.74	10.72	9.91	8.83	9.68	9.67	8.16	9.94	8.88	7.88	7.88	8.40
Iowa	Clinton	12.44	11.52	10.63	9.43	10.38	10.37	8.68	10.84	9.61	8.55	8.55	9.14
Iowa	Johnson	11.64	10.73	9.87	8.71	9.60	9.61	7.98	10.00	8.87	7.81	7.81	8.35
Iowa	Linn	11.35	10.51	9.69	8.51	9.39	9.40	7.79	9.83	8.75	7.63	7.63	8.18
Iowa	Polk	10.85	9.96	9.22	8.24	8.98	9.00	7.62	9.26	8.31	7.35	7.35	7.82

State	County	'99-'01 *EPA CSA Analysis* PM2.5 1999-2001 Ambient Design Value	2010 PM2.5 Base case 2010	2010 PM2.5 Clear Skies 2010	2010 Jeffords	2010 Straw	2010 Carper	2010 No EGU	2020 *EPA CSA Analysis* PM2.5 Base case 2020	2020 PM2.5 Clear Skies 2020	2020 Jeffords	2020 Straw	2020 Carper
Iowa	Scott	13.03	12.17	11.24	10.04	10.98	10.99	9.26	11.45	10.21	9.11	9.11	9.70
Iowa	Woodbury	10.00	9.19	8.57	7.66	8.40	8.43	7.10	8.55	7.75	6.83	6.83	7.32
Kansas	Johnson	11.80	10.78	10.06	9.07	9.79	9.86	8.50	10.17	9.24	8.32	8.32	8.80
Kansas	Linn	11.20	10.22	9.46	8.26	9.14	9.22	7.62	9.56	8.56	7.50	7.50	8.08
Kansas	Sedgwick	11.77	10.87	10.21	8.98	9.86	9.97	8.35	10.33	9.50	8.38	8.38	9.03
Kansas	Shawnee	11.25	10.32	9.61	8.55	9.34	9.41	7.90	9.76	8.87	7.83	7.83	8.37
Kentucky	Boyd	15.46	14.49	12.76	11.32	12.20	12.31	10.15	13.72	11.55	10.76	10.76	11.02
Kentucky	Bullitt	16.04	14.39	12.81	11.09	12.16	12.29	9.69	13.61	11.35	10.24	10.24	10.68
Kentucky	Campbell	15.46	14.29	12.79	11.30	12.25	12.35	10.09	13.53	11.54	10.56	10.56	10.86
Kentucky	Carter	12.90	11.92	10.55	9.15	9.99	10.09	8.09	11.25	9.32	8.47	8.76	8.03
Kentucky	Fayette	16.82	15.29	13.64	11.73	12.84	12.98	10.30	14.46	12.14	10.96	10.96	11.35
Kentucky	Franklin	14.53	13.19	11.74	10.03	11.00	11.13	8.77	12.46	10.42	9.35	9.35	9.69
Kentucky	Jefferson	17.08	15.70	14.12	12.33	13.42	13.55	10.84	15.05	12.83	11.62	11.62	12.07
Kentucky	Kenton	15.86	14.61	13.05	11.37	12.45	12.54	10.13	13.91	11.79	10.67	10.67	11.04
Kentucky	McCracken	15.10	13.85	12.53	10.87	11.87	11.99	9.61	13.19	11.41	10.37	10.73	9.83
Kentucky	Pike	16.14	14.87	13.24	11.47	12.49	12.66	10.19	14.08	11.72	10.85	10.85	11.15
Kentucky	Warren	15.41	13.81	12.33	10.43	11.53	11.69	9.24	12.96	10.80	9.65	9.65	10.05
Louisiana	Caddo	13.69	12.86	11.96	10.81	11.67	11.74	10.17	12.57	11.28	10.61	10.61	11.09
Louisiana	Calcasieu	12.75	12.36	11.78	10.50	11.38	11.45	9.96	12.34	11.38	10.65	10.65	11.07
Louisiana	East Baton Roug	14.55	14.03	13.41	12.30	12.96	13.04	11.75	14.25	13.19	12.56	12.56	12.85
Louisiana	Iberville	13.88	13.39	12.72	11.45	12.22	12.31	10.81	13.51	12.35	11.61	11.96	11.66
Louisiana	Jefferson	13.59	13.09	12.37	11.14	11.89	11.97	10.52	13.03	11.84	11.13	11.47	11.19
Louisiana	Lafayette	12.44	11.76	11.10	9.85	10.62	10.70	9.25	11.59	10.50	9.74	9.74	10.10
Louisiana	Orleans	14.15	13.63	12.89	11.67	12.35	12.45	11.00	13.57	12.34	11.64	11.64	11.92
Louisiana	Ouachita	13.04	12.31	11.57	10.45	11.19	11.27	9.82	12.17	11.05	10.32	10.32	10.70
Louisiana	Rapides	13.26	12.38	11.70	10.46	11.25	11.32	9.80	12.50	11.37	10.62	10.62	11.00
Louisiana	Tangipahoa	13.47	12.61	11.88	10.68	11.36	11.46	10.00	12.36	11.13	10.44	10.44	10.73
Louisiana	West Baton Rou	14.06	13.56	12.95	11.88	12.51	12.59	11.34	13.77	12.74	12.12	12.12	12.40
Maine	Androscoggin	10.31	9.35	8.77	8.44	8.73	8.76	8.07	8.97	8.21	8.11	8.11	8.18
Maine	Aroostook	10.79	10.37	9.89	9.62	9.85	9.87	9.34	10.21	9.59	9.51	9.51	9.57
Maine	Cumberland	11.65	10.51	9.88	9.59	9.90	9.94	9.21	10.06	9.23	9.18	9.18	9.26
Maine	Hancock	6.03	5.51	5.08	4.87	5.05	5.08	4.67	5.34	4.77	4.75	4.75	4.79
Maine	Kennebec	9.97	9.04	8.47	8.16	8.43	8.47	7.82	8.66	7.91	7.83	7.83	7.90
Maine	Oxford	10.45	9.74	9.10	8.62	8.90	8.93	8.28	9.42	8.61	8.53	8.60	8.04
Maine	Penobscot	9.38	8.55	7.99	7.72	7.97	8.00	7.40	8.21	7.49	7.43	7.43	7.49
Maryland	Baltimore city	17.83	16.62	14.98	13.88	14.47	14.57	12.67	15.83	13.57	12.91	12.91	13.07

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Massachusetts	Hampden	14.10	13.02	12.18	11.67	12.07	12.10	11.09	12.55	11.42	11.17	11.17	11.26
Massachusetts	Hampshire	9.02	8.27	7.69	7.19	7.46	7.50	6.70	7.92	7.16	7.42	6.98	6.47
Massachusetts	Worcester	12.68	11.55	10.81	10.42	10.75	10.78	9.95	10.99	9.99	9.79	9.79	9.88
Michigan	Allegan	12.23	11.44	10.81	9.93	10.63	10.64	8.99	10.85	9.84	8.97	8.97	9.46
Michigan	Berrien	12.51	11.67	10.89	9.96	10.67	10.69	9.13	11.02	9.89	9.03	9.03	9.49
Michigan	Genesee	12.70	11.90	11.13	10.39	10.96	10.97	9.70	11.30	10.25	9.56	9.56	9.87
Michigan	Ingham	13.15	12.23	11.43	10.52	11.24	11.24	9.68	11.55	10.42	9.55	9.55	9.98
Michigan	Kalamazoo	15.01	13.99	13.02	11.94	12.76	12.78	11.01	13.22	11.84	10.88	10.88	11.37
Michigan	Kent	14.06	13.11	12.29	11.29	12.07	12.08	10.37	12.39	11.20	10.27	10.27	10.76
Michigan	Macomb	13.25	12.52	11.72	11.02	11.56	11.56	10.34	11.94	10.84	10.24	10.24	10.51
Michigan	Muskegon	12.19	11.48	10.84	10.04	10.68	10.69	9.29	10.95	9.97	9.15	9.15	9.64
Michigan	Ottawa	13.33	12.43	11.65	10.70	11.44	11.45	9.82	11.75	10.62	9.72	9.72	10.19
Michigan	St. Clair	13.80	13.08	12.22	11.28	12.00	12.01	10.42	12.53	11.33	11.28	10.90	10.22
Michigan	Wayne	18.91	17.98	16.81	15.76	16.56	16.57	14.76	17.25	15.62	14.75	14.75	15.11
Mississippi	DeSoto	13.98	12.70	11.63	10.30	11.01	11.15	9.54	12.02	10.46	10.92	10.10	9.39
Mississippi	Hancock	12.16	11.39	10.70	9.64	10.27	10.38	8.99	11.26	10.09	9.55	9.55	9.80
Mississippi	Hinds	15.09	13.94	13.02	11.73	12.51	12.61	11.02	13.46	11.95	11.24	11.24	11.57
Mississippi	Jackson	13.82	12.93	12.16	10.87	11.49	11.70	10.03	12.79	11.21	10.71	10.71	10.94
Mississippi	Jones	16.62	15.21	14.16	12.62	13.50	13.66	11.70	14.76	12.96	12.16	12.16	12.50
Mississippi	Lee	14.20	12.84	11.80	10.26	11.16	11.30	9.32	12.19	10.54	9.62	9.62	9.99
Missouri	Buchanan	12.43	11.34	10.55	9.42	10.26	10.33	8.69	10.63	9.60	8.53	8.53	9.08
Missouri	Cedar	11.52	10.51	9.63	8.34	9.28	9.36	7.63	9.80	8.68	7.55	7.55	8.16
Missouri	Clay	12.84	11.83	11.09	10.06	10.81	10.88	9.41	11.26	10.31	9.30	9.30	9.81
Missouri	Greene	12.24	11.27	10.30	8.96	9.91	9.98	8.14	10.59	9.34	8.25	8.25	8.80
Missouri	Jackson	13.87	12.76	11.98	10.89	11.68	11.75	10.19	12.14	11.14	10.07	10.07	10.61
Missouri	Jasper	13.69	12.54	11.50	9.95	11.05	11.15	9.14	11.71	10.39	9.08	9.08	9.79
Missouri	Jefferson	14.97	14.11	12.93	11.58	12.55	12.60	10.69	13.57	12.01	10.86	10.86	11.38
Missouri	Monroe	11.01	10.08	9.23	8.15	8.96	8.99	7.44	9.42	8.32	7.38	7.38	7.87
Missouri	St. Charles	14.64	13.85	12.85	11.54	12.47	12.50	10.68	13.33	11.96	10.80	10.80	11.33
Missouri	Ste. Genevieve	14.19	13.08	11.87	10.45	11.48	11.54	9.51	12.37	10.77	9.62	9.62	10.17
Missouri	St. Louis	14.12	13.35	12.40	11.00	11.88	11.93	10.19	12.84	11.53	10.29	10.29	10.77
Missouri	St. Louis city	16.28	15.32	14.13	12.73	13.73	13.78	11.81	14.72	13.12	11.92	11.92	12.47
Montana	Lewis And Clark	8.50	8.30	8.28	8.25	8.26	8.27	8.23	8.32	8.29	8.23	8.25	8.27
Montana	Lincoln	16.40	15.52	15.49	15.46	15.47	15.48	15.44	14.97	14.94	14.88	14.90	14.92
Montana	Missoula	11.80	11.15	11.12	11.09	11.10	11.11	11.07	10.84	10.81	10.75	10.77	10.79
Montana	Yellowstone	8.00	7.63	7.53	7.50	7.51	7.52	7.48	7.55	7.41	7.35	7.37	7.39

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Nebraska	Lancaster	10.52	9.65	8.96	8.93	8.94	8.95	8.91	9.04	8.19	8.13	8.15	8.17
Nevada	Clark	11.00	10.39	10.32	10.29	10.30	10.31	10.27	9.83	9.71	9.65	9.67	9.69
Nevada	Washoe	9.70	8.93	8.92	8.89	8.90	8.91	8.87	8.55	8.53	8.47	8.49	8.51
New Jersey	Hudson	17.22	14.65	13.77	13.17	13.51	13.56	12.58	14.11	12.86	12.46	12.46	12.55
New Jersey	Mercer	14.31	13.46	12.45	11.97	12.23	12.26	11.51	12.95	11.54	12.11	11.31	10.76
New Jersey	Union	16.27	14.20	13.56	13.17	13.40	13.44	12.75	13.91	12.96	12.68	12.68	12.77
New Mexico	Dona Ana	10.90	10.15	10.00	9.97	9.98	9.99	9.95	9.92	9.71	9.65	9.67	9.69
New Mexico	Grant	5.70	5.52	5.47	5.44	5.45	5.46	5.42	5.52	5.45	5.39	5.41	5.43
New Mexico	Lea	6.90	6.47	6.30	6.27	6.28	6.29	6.25	6.30	6.07	6.01	6.03	6.05
New Mexico	Sandoval	5.00	4.91	4.84	4.81	4.82	4.83	4.79	4.96	4.88	4.82	4.84	4.86
New Mexico	Santa Fe	4.80	4.53	4.47	4.44	4.45	4.46	4.42	4.45	4.36	4.30	4.32	4.34
New York	New York	18.05	16.35	15.37	14.60	15.02	15.06	13.96	15.49	14.14	13.60	13.60	13.70
North Carolina	Alamance	15.32	13.91	12.59	11.37	12.17	12.34	10.31	13.05	11.07	10.71	10.71	10.93
North Carolina	Cabarrus	15.67	13.71	12.67	11.07	12.04	12.18	10.04	12.88	11.14	10.28	10.28	10.55
North Carolina	Catawba	17.11	15.37	14.01	12.12	13.20	13.35	10.97	14.43	12.19	11.32	11.32	11.59
North Carolina	Chatham	13.42	12.22	11.08	9.90	10.62	10.75	8.98	11.50	9.72	9.28	9.28	9.47
North Carolina	Cumberland	15.44	14.24	12.92	11.50	12.27	12.41	10.50	13.55	11.55	10.91	10.91	11.10
North Carolina	Davidson	17.28	15.58	14.27	12.56	13.59	13.74	11.40	14.69	12.53	11.79	11.79	12.03
North Carolina	Duplin	12.65	11.57	10.46	9.22	9.89	10.00	8.35	11.00	9.34	8.71	8.71	8.88
North Carolina	Durham	15.35	14.25	12.91	11.58	12.38	12.51	10.58	13.50	11.49	10.97	10.97	11.15
North Carolina	Forsyth	16.23	14.52	13.26	11.69	12.65	12.88	10.53	13.60	11.63	10.88	10.88	11.15
North Carolina	Gaston	15.29	13.87	12.89	11.16	12.22	12.31	10.21	13.12	11.25	10.49	10.49	10.77
North Carolina	Guilford	16.25	14.79	13.41	11.72	12.65	12.80	10.62	13.86	11.79	12.60	11.34	10.14
North Carolina	Haywood	15.38	13.90	12.74	10.88	11.93	12.10	9.75	13.24	11.18	10.30	10.30	10.65
North Carolina	McDowell	16.17	14.61	13.33	11.56	12.60	12.77	10.40	13.91	11.76	10.97	10.97	11.25
North Carolina	Mecklenburg	16.77	15.22	14.08	12.29	13.25	13.41	11.23	14.33	12.37	11.49	11.49	11.74
North Carolina	Mitchell	15.46	13.97	12.71	10.85	11.94	12.12	9.69	13.24	11.06	10.28	10.28	10.60
North Carolina	New Hanover	12.19	11.33	10.43	9.50	10.08	10.18	8.74	10.98	9.51	9.10	9.10	9.28
North Carolina	Onslow	12.14	11.16	10.13	9.04	9.65	9.76	8.21	10.63	9.05	8.53	8.53	8.69
North Carolina	Orange	14.32	13.05	11.83	10.55	11.33	11.47	9.57	12.28	10.38	9.90	9.90	10.11
North Carolina	Swain	14.12	12.83	11.69	9.99	10.95	11.13	8.94	12.15	10.19	9.43	9.43	9.75
North Carolina	Wake	15.30	14.21	12.87	11.49	12.29	12.42	10.49	13.46	11.45	10.85	10.85	11.03
North Carolina	Wayne	15.30	14.11	12.75	11.31	12.09	12.24	10.24	13.43	11.44	10.76	10.76	10.95
North Dakota	Cass	8.58	7.90	7.45	6.78	7.27	7.30	6.43	7.40	6.86	6.15	6.15	6.51
North Dakota	Mercer	6.90	6.37	6.01	5.50	5.90	5.92	5.22	5.68	5.52	5.39	5.24	4.98
North Dakota	Steele	6.93	6.36	6.03	5.52	5.92	5.94	5.23	5.91	5.51	5.41	5.23	4.98

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Ohio	Butler	17.41	16.14	14.57	13.15	14.06	14.15	11.83	15.24	13.14	12.19	12.19	12.46
Ohio	Cuyahoga	20.25	19.20	17.69	16.60	17.37	17.42	15.56	18.37	16.38	15.64	15.64	15.94
Ohio	Franklin	18.13	16.80	15.06	13.73	14.65	14.74	12.52	16.00	13.78	12.97	12.97	13.29
Ohio	Hamilton	19.29	17.86	16.04	14.26	15.40	15.52	12.79	16.92	14.49	13.31	13.31	13.68
Ohio	Jefferson	18.90	18.08	16.21	15.02	15.81	15.92	13.80	17.36	15.06	14.44	14.44	14.70
Ohio	Lake	13.95	13.47	12.25	11.51	12.12	12.15	10.72	12.91	11.34	10.88	10.88	11.10
Ohio	Lorain	15.08	14.28	13.14	11.94	12.69	12.76	10.92	13.58	12.08	12.41	11.65	10.79
Ohio	Mahoning	16.42	15.46	13.79	12.78	13.52	13.59	11.73	14.66	12.63	12.08	12.08	12.30
Ohio	Montgomery	17.65	16.50	14.92	13.45	14.40	14.49	12.22	15.65	13.57	12.49	12.49	12.84
Ohio	Portage	15.29	14.47	13.00	12.01	12.74	12.79	11.05	13.75	11.93	11.34	11.34	11.58
Ohio	Scioto	20.04	18.54	16.41	14.68	15.79	15.94	13.13	17.42	14.71	13.83	13.83	14.13
Ohio	Stark	18.29	17.16	15.26	13.91	14.84	14.92	12.65	16.20	13.85	13.05	13.05	13.35
Ohio	Summit	17.34	16.42	14.77	13.63	14.46	14.52	12.56	15.61	13.56	12.88	12.88	13.15
Ohio	Trumbull	16.16	15.20	13.60	12.61	13.33	13.40	11.60	14.41	12.45	11.90	11.90	12.12
Oregon	Benton	7.40	6.97	6.97	6.94	6.95	6.96	6.92	6.79	6.78	6.72	6.74	6.76
Oregon	Columbia	6.60	6.08	6.06	6.03	6.04	6.05	6.01	5.82	5.80	5.74	5.76	5.78
Oregon	Jackson	11.30	10.34	10.33	10.30	10.31	10.32	10.28	9.77	9.76	9.70	9.72	9.74
Oregon	Klamath	9.70	9.13	9.12	9.09	9.10	9.11	9.07	8.86	8.85	8.79	8.81	8.83
Oregon	Lake	7.60	7.18	7.17	7.14	7.15	7.16	7.12	6.98	6.97	6.91	6.93	6.95
Oregon	Lane	13.20	12.23	12.21	12.18	12.19	12.20	12.16	11.77	11.75	11.69	11.71	11.73
Oregon	Marion	8.20	7.59	7.58	7.55	7.56	7.57	7.53	7.28	7.27	7.21	7.23	7.25
Oregon	Multnomah	9.10	8.58	8.57	8.54	8.55	8.56	8.52	8.36	8.35	8.29	8.31	8.33
Oregon	Umatilla	8.80	8.17	8.15	8.12	8.13	8.14	8.10	7.82	7.80	7.74	7.76	7.78
Oregon	Washington	7.80	7.35	7.34	7.31	7.32	7.33	7.29	7.16	7.15	7.09	7.11	7.13
Pennsylvania	Allegheny	21.02	19.30	16.73	14.97	16.00	16.18	13.56	18.03	15.11	14.15	14.15	14.44
Pennsylvania	Berks	15.62	14.48	13.15	12.23	12.72	12.79	11.36	13.82	11.98	11.38	11.38	11.51
Pennsylvania	Cambria	15.32	14.19	12.25	11.10	11.82	11.94	9.99	13.32	11.02	10.44	10.44	10.64
Pennsylvania	Dauphin	15.52	14.33	12.69	11.57	12.12	12.21	10.53	13.62	11.37	10.70	10.70	10.85
Pennsylvania	Lancaster	16.91	15.43	13.82	12.58	13.18	13.27	11.56	14.53	12.39	11.58	11.58	11.73
Pennsylvania	Philadelphia	16.55	15.66	14.59	13.68	14.13	14.19	12.91	15.18	13.66	13.06	13.06	13.18
Pennsylvania	Washington	15.55	14.29	12.31	10.92	11.73	11.87	9.83	13.33	11.10	10.35	10.35	10.57
Pennsylvania	Westmoreland	15.60	14.30	12.36	11.07	11.83	11.96	10.03	13.34	11.14	10.44	10.44	10.65
Pennsylvania	York	16.25	15.03	13.46	12.41	12.97	13.05	11.35	14.22	12.12	11.45	11.45	11.61
South Carolina	Charleston	12.62	11.85	11.04	9.74	10.34	10.47	8.94	11.62	10.19	9.35	9.35	9.52
South Carolina	Georgetown	13.91	12.90	11.92	10.35	11.15	11.31	9.44	12.57	10.79	11.07	10.29	9.25
South Carolina	Greenville	16.51	15.16	13.89	11.87	12.99	13.17	10.78	14.33	12.01	11.12	11.12	11.45

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South Carolina	Lexington	15.62	14.43	13.28	11.73	12.53	12.74	10.70	13.73	11.69	10.99	10.99	11.32
South Carolina	Oconee	12.29	11.16	10.19	8.85	9.53	9.67	8.07	10.51	8.72	7.50	8.31	7.47
South Carolina	Richland	15.39	14.25	13.10	11.50	12.29	12.47	10.49	13.58	11.54	10.78	10.78	11.07
South Carolina	Spartanburg	15.37	14.09	12.92	11.06	12.10	12.27	10.04	13.30	11.18	10.35	10.35	10.66
South Dakota	Minnehaha	10.42	9.62	8.94	8.91	8.92	8.93	8.89	8.88	8.06	8.00	8.02	8.04
Tennessee	Davidson	17.05	15.37	13.95	12.01	13.19	13.33	10.75	14.62	12.49	11.32	11.32	11.78
Tennessee	Hamilton	18.46	16.83	15.37	13.37	14.56	14.77	12.09	15.88	13.44	12.63	12.63	13.01
Tennessee	Knox	20.42	18.41	16.74	14.21	15.55	15.84	12.72	17.41	14.53	13.35	13.35	13.78
Tennessee	Roane	17.02	15.22	13.78	11.60	12.75	13.07	10.27	14.35	11.88	10.85	10.85	11.24
Tennessee	Shelby	15.56	14.86	13.75	12.23	13.17	13.36	11.30	14.26	12.51	11.55	11.55	12.03
Tennessee	Sullivan	16.98	15.35	13.92	11.93	13.11	13.24	10.74	14.60	12.16	11.28	11.28	11.61
Tennessee	Sumner	15.68	14.12	12.79	10.96	12.06	12.20	9.78	13.42	11.43	10.32	10.32	10.75
Utah	Davis	9.00	8.83	8.79	8.76	8.77	8.78	8.74	8.67	8.61	8.55	8.57	8.59
Utah	Salt Lake	13.60	13.35	13.28	13.25	13.26	13.27	13.23	13.10	13.01	12.95	12.97	12.99
Utah	Tooele	7.20	7.22	7.19	7.16	7.17	7.18	7.14	7.29	7.25	7.19	7.21	7.23
Utah	Utah	10.40	10.11	10.04	10.01	10.02	10.03	9.99	10.02	9.93	9.87	9.89	9.91
Utah	Weber	8.80	8.56	8.51	8.48	8.49	8.50	8.46	8.46	8.39	8.33	8.35	8.37
Vermont	Bennington	9.86	9.12	8.45	8.01	8.34	8.37	7.57	8.81	7.91	7.71	7.71	7.78
Vermont	Chittenden	6.76	6.31	5.83	5.65	5.84	5.86	5.39	6.07	5.46	5.41	5.41	5.46
Vermont	Rutland	11.32	10.46	9.71	9.22	9.59	9.62	8.75	10.06	9.07	8.84	8.84	8.93
Vermont	Washington	10.47	9.72	9.04	8.60	8.93	8.96	8.17	9.35	8.47	8.26	8.26	8.34
Virginia	Bristol city	16.01	14.33	13.00	11.18	12.22	12.38	10.08	13.55	11.35	10.52	10.52	10.81
Virginia	Newport News ci	12.67	11.88	10.91	10.05	10.62	10.70	9.38	11.55	10.17	9.74	9.74	9.94
Virginia	Roanoke city	15.24	14.00	12.42	10.82	11.76	11.90	9.67	13.20	11.07	10.31	10.31	10.53
Virginia	Virginia Beach ci	13.21	12.41	11.39	10.45	11.06	11.15	9.70	12.10	10.60	10.14	10.14	10.35
Washington	King	11.90	11.38	11.34	11.31	11.32	11.33	11.29	11.13	11.07	11.01	11.03	11.05
Washington	Pierce	11.70	11.00	10.96	10.93	10.94	10.95	10.91	10.69	10.63	10.57	10.59	10.61
Washington	Snohomish	11.40	10.66	10.61	10.58	10.59	10.60	10.56	10.25	10.19	10.13	10.15	10.17
Washington	Spokane	10.40	9.61	9.58	9.55	9.56	9.57	9.53	9.14	9.11	9.05	9.07	9.09
Washington	Thurston	9.70	8.72	8.68	8.65	8.66	8.67	8.63	8.25	8.20	8.14	8.16	8.18
Washington	Whatcom	7.90	7.48	7.45	7.42	7.43	7.44	7.40	7.26	7.23	7.17	7.19	7.21
West Virginia	Berkeley	16.01	14.77	12.93	11.65	12.37	12.49	10.43	13.88	11.55	10.92	10.92	11.05
West Virginia	Brooke	17.40	16.65	14.91	13.80	14.54	14.64	12.67	15.97	13.84	13.27	13.27	13.51
West Virginia	Cabell	17.85	16.51	14.50	12.97	13.97	14.10	11.65	15.55	13.05	12.31	12.31	12.60
West Virginia	Hancock	17.36	16.60	14.88	13.77	14.50	14.60	12.64	15.93	13.82	13.23	13.23	13.47
West Virginia	Harrison	14.78	13.63	11.75	10.39	11.27	11.39	9.12	12.83	10.54	9.94	9.94	10.15

State	County	'99-'01 EPA CSA Analysis PM2.5 1999-2001 Ambient Design Value	2010 PM2.5 Base case 2010	2010 PM2.5 Clear Skies 2010	2010 Jeffords	2010 Straw	2010 Carper	2010 No EGU	2020 EPA CSA Analysis PM2.5 Base case 2020	2020 PM2.5 Clear Skies 2020	2020 Jeffords	2020 Straw	2020 Carper
West Virginia	Kanawha	18.39	17.19	14.89	13.43	14.42	14.55	12.03	16.25	13.50	12.85	12.85	13.14
West Virginia	Marshall	16.52	15.58	13.43	11.96	12.88	12.99	10.70	14.57	12.18	11.52	11.52	11.72
West Virginia	Monongalia	14.95	13.83	11.80	10.51	11.35	11.47	9.27	12.91	10.61	10.05	10.05	10.23
West Virginia	Ohio	15.66	14.69	12.59	11.31	12.14	12.31	10.13	13.74	11.37	10.76	10.76	10.99
West Virginia	Raleigh	14.02	12.83	11.31	9.95	10.81	10.93	8.82	12.09	10.00	9.42	9.42	9.64
West Virginia	Summers	10.89	9.96	8.70	7.62	8.31	8.41	6.72	9.36	7.71	7.24	7.24	7.41
West Virginia	Wood	17.62	16.36	14.21	12.71	13.73	13.86	11.33	15.39	12.91	12.18	12.18	12.47
Wisconsin	Brown	11.43	10.63	9.94	9.11	9.78	9.77	8.45	10.06	9.12	8.30	8.30	8.75
Wisconsin	Dane	13.16	12.22	11.37	10.32	11.17	11.17	9.60	11.52	10.36	9.33	9.33	9.93
Wisconsin	Dodge	11.77	10.86	10.08	9.13	9.88	9.88	8.43	10.18	9.10	8.16	8.16	8.66
Wisconsin	Door	8.02	7.58	7.14	6.65	7.06	7.06	6.21	7.31	6.72	6.24	6.24	6.51
Wisconsin	Douglas	8.32	7.88	7.52	7.12	7.47	7.47	6.80	7.83	7.35	6.97	6.97	7.22
Wisconsin	Grant	12.27	11.24	10.37	9.54	10.22	10.22	8.90	10.46	9.31	9.48	8.96	8.48
Wisconsin	Jefferson	12.52	11.60	10.80	9.86	10.61	10.61	9.15	10.94	9.81	8.89	8.89	9.40
Wisconsin	Kenosha	12.14	11.60	10.87	9.96	10.72	10.73	9.29	11.13	10.12	9.21	9.21	9.79
Wisconsin	Manitowoc	10.25	9.55	8.94	8.18	8.78	8.77	7.56	9.08	8.23	7.44	7.44	7.87
Wisconsin	Milwaukee	14.18	13.56	12.77	11.86	12.61	12.62	11.10	13.08	11.93	10.97	10.97	11.53
Wisconsin	Outagamie	11.27	10.47	9.82	9.05	9.66	9.66	8.45	9.97	9.08	8.29	8.29	8.72
Wisconsin	Vilas	6.39	5.97	5.61	5.16	5.53	5.53	4.81	5.70	5.23	4.40	5.03	4.76
Wisconsin	Waukesha	14.10	13.28	12.45	11.47	12.26	12.26	10.73	12.63	11.45	10.47	10.47	11.03
Wisconsin	Winnebago	11.19	10.34	9.66	8.85	9.50	9.50	8.21	9.75	8.82	8.01	8.01	8.45
Wisconsin	Wood	10.61	9.71	9.09	8.36	8.96	8.96	7.80	9.15	8.31	7.13	8.00	7.56
Wyoming	Laramie	5.40	5.25	5.14	5.11	5.12	5.13	5.09	5.32	5.17	5.11	5.13	5.15
Wyoming	Sheridan	10.90	10.21	10.05	10.02	10.03	10.04	10.00	10.02	9.79	9.73	9.75	9.77

Synapse
Energy Economics, Inc.

Climate Change and Power:

Carbon Dioxide Emissions Costs and Electricity Resource Planning

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Executive Summary

The fact of human-induced global climate change as a consequence of our greenhouse gas emissions is now well established, and the only remaining questions among mainstream scientists concern the nature and timing of future disruptions and dislocations and the magnitude of the socio-economic impacts. It is also generally agreed that different CO_2 emissions trajectories will lead to varying levels of environmental, economic, and social costs – which means that the more sharply and the sooner we can reduce emissions, the greater the avoided costs will be.

This report is designed to assist utilities, regulators, consumer advocates and others in projecting the future cost of complying with carbon dioxide regulations in the United States.[1] These cost forecasts are necessary for use in long-term electricity resource planning, in electricity resource economics, and in utility risk management.

We recognize that there is considerable uncertainty inherent in projecting long-term carbon emissions costs, not least of which concerns the timing and form of future emissions regulations in the United States. However, this uncertainty is no reason to ignore this very real component of future production cost. In fact, this type of uncertainty is similar to that of other critical electricity cost drivers such as fossil-fuel prices.

Accounting for Climate Change Regulations in Electricity Planning

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions, but has only 4.6 percent of the population.

Within the United States, the electricity sector is responsible for roughly 39% of CO_2 emissions. Within the electricity industry, roughly 82% of CO_2 emissions come from coal-fired plants, roughly 13% come from gas-fired plants, and roughly 5% come from oil-fired plants.

Because of its contribution to US and worldwide CO_2 emissions, the US electricity industry will clearly need to play a critical role in reducing greenhouse gas (GHG) emissions. In addition, the electricity industry is composed of large point sources of emissions, and it is often easier and more cost-effective to control emissions from large sources than multiple small sources. Analyses by the US Energy Information Administration indicate that 65% to 90% of energy-related carbon dioxide emissions reductions are likely to come from the electric sector under a wide range of economy-wide federal policy scenarios.[2]

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[1] This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

[2] EIA 2003, page 13; EIA 2004, page 5; EIA 2006, page 19.

In this context, the failure of entities in the electric sector to anticipate the future costs associated with carbon dioxide regulations is short-sighted, economically unjustifiable, and ultimately self-defeating. Long-term resource planning and investment decisions that do not quantify the likely future cost of CO_2 regulations will understate the true cost of future resources, and thus will result in uneconomic, imprudent decisions. Generating companies will naturally attempt to pass these unnecessarily high costs on to electricity ratepayers. Thus, properly accounting for future CO_2 regulations is as much a consumer issue as it is an issue of prudent resource selection.

Some utility planners argue that the cost of complying with future CO_2 regulations involves too much uncertainty, and thus they leave the cost out of the planning process altogether. This approach results in making an implicit assumption that the cost of complying with future CO_2 regulations will be zero. This assumption of zero cost will apply to new generation facilities that may operate for 50 or more years into the future. In this report, we demonstrate that under all reasonable forecasts of the near- to mid-term future, the cost of complying with CO_2 regulations will certainly be greater than zero.

Federal Initiatives to Regulate Greenhouse Gases

The scientific consensus on climate change has spurred efforts around the world to reduce greenhouse gas emissions, many of which are grounded in the United Nations Framework Convention on Climate Change (UNFCCC). The United States is a signatory to this convention, which means that it has agreed to a goal of “stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system.” However, the United States has not yet agreed to the legally binding limits on greenhouse gas emissions contained in the Kyoto Protocol, a supplement to the UNFCCC.

Table ES-1. Summary of Federal Mandatory Emission Reduction Legislation

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Nonetheless, there have been several important attempts at the federal level to limit the emissions of greenhouse gases in the United States. Table ES-1 presents a summary of federal legislation that has been introduced in recent years. Most of this legislation includes some form of mandatory national limits on the emissions of greenhouse gases, as well as market-based cap and trade mechanisms to assist in meeting those limits.

State and Regional Initiatives to Regulate Greenhouse Gases

Many states across the country have not waited for federal policies, and are developing and implementing climate change-related policies that have a direct bearing on electric resource planning. States, acting individually and through regional coordination, have been the leaders on climate change policies in the United States.

State policies generally fall into the following categories: (a) direct policies that require specific emission reductions from electric generation sources; (b) indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (c) legal proceedings; or (d) voluntary programs including educational efforts and energy planning. Table ES-2 presents a summary of types of policies with recent state policies on climate change listed on the right side of the table.

Table ES-2. Summary of Individual State Climate Change Policies

Type of Policy	State Examples
Direct	
• Power plant emission restrictions (e.g. cap or emission rate)	• MA, NH
• New plant emission restrictions	• OR, WA
• State GHG reduction targets	• CT, NJ, ME, MA, CA, NM, NY, OR, WA
• Fuel/generation efficiency	• CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy)	
• Load-based GHG cap	• CA
• GHG in resource planning	• CA, WA, OR, MT, KY
• Renewable portfolio standards	• 22 states and D.C.
• Energy efficiency/renewable charges and funding; energy efficiency programs	• More than half the states
• Net metering, tax incentives	• 41 states
Lawsuits	
• States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act	• States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI
• States sue individual companies to reduce GHG emissions	• NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states require that regulated utilities evaluate costs or risks associated with greenhouse gas emissions regulations in long-range planning or resource procurement. Some of the states require that companies use a specific value, while other states require that companies consider the risk of future regulation in their planning process. Table ES-3 summarizes state requirements for considering greenhouse gas emissions in electricity resource planning.

Table ES-3. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

States are not just acting individually; there are several examples of innovative regional policy initiatives. To date, there are regional initiatives including Northeastern and Mid-Atlantic states (CT, DE, MD, ME, NH, NJ, NY, and VT), West Coast states (CA, OR, WA), Southwestern states (NM, AZ), and Midwestern states (IL, IA, MI, MN, OH, WI).

The Northeastern and Mid-Atlantic states recently reached agreement on the creation of the Regional Greenhouse Gas Initiative (RGGI); a multi-year cooperative effort to design a regional cap and trade program covering CO_2 emissions from power plants in the region. The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes.
- Certain offset provisions that increase flexibility to moderate price impacts.
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.

Electric Industry Actions to Address Greenhouse Gases

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have begun to evaluate the risks associated with future greenhouse gas regulation and take steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints.

Recently, eight US-based utility companies have joined forces to create the “Clean Energy Group.” This group’s mission is to seek “national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013.”

In addition, leaders of electric companies such as Duke and Exelon have vocalized support for mandatory national carbon regulation. These companies urge a mandatory federal policy, stating that climate change is a pressing issue that must be resolved, that voluntary action is not sufficient, and that companies need regulatory certainty to make appropriate decisions. Even companies that do not advocate federal requirements, anticipate their adoption and urge regulatory certainty. Several companies have established greenhouse gas reduction goals for their company.

Several electric utilities and electric generation companies have incorporated specific forecasts of carbon regulation and costs into their long term planning practices. Table ES-4 illustrates the range of carbon cost values, in \$/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table ES-4. CO_2 Cost Estimates Used in Electricity Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2004, pages 62-63; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

Synapse Forecast of Carbon Dioxide Allowance Prices

This report presents our current forecast of the most likely costs of compliance with future climate change regulations. In making this forecast we review a range of current estimates from a variety of different sources. We review the results of several analyses of federal policy proposals, and a few analyses of the Kyoto Protocol. We also look briefly at carbon markets in the European Union to demonstrate the levels at which carbon dioxide emissions are valued in an active market.

Figure ES-1 presents CO_2 allowance price forecasts from the range of recent studies that we reviewed. All of the studies here are based on the costs associated with complying with potential CO_2 regulations in the United States. The range of these price forecasts reflects the range of policy initiatives that have been proposed in the United States, as well as the diversity of economic models and methodologies used to estimate their price impacts.

Figure ES-1 superimposes the Synapse long term forecasts of CO_2 allowance prices upon the other forecasts gleaned from the literature. In order to help address the uncertainty involved in forecasting CO_2 prices, we present a "base case" forecast as well as a "low case" and a "high case." All three forecasts are based on our review of both regulatory trends and economic models, as outlined in this document.

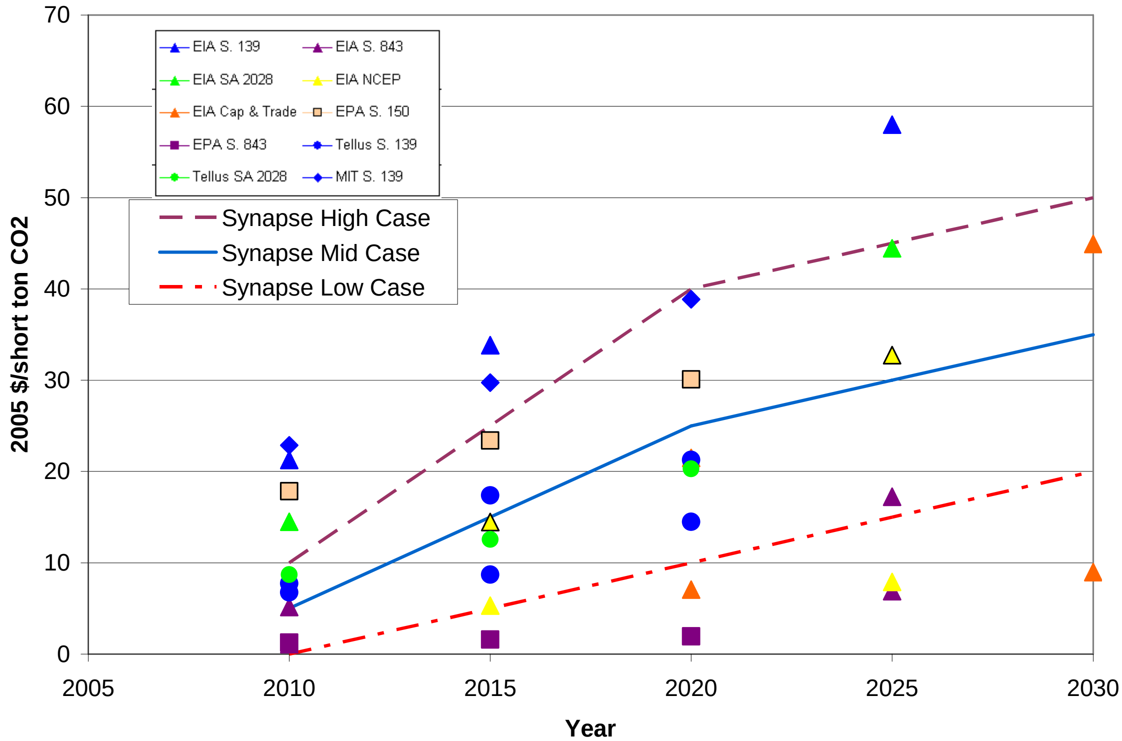

Figure ES-1. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.3.

As with any forecast, our forecast is likely to be revised over time as the form and timing of carbon emission regulations come increasingly into focus. It is our judgment that this range represents a reasonable quantification of what is known today about future carbon emissions costs in the United States. As such, it is appropriate for use in long range resource planning purposes until better information or more clarity become available.

Additional Costs Associated with Greenhouse Gases

This report summarizes current policy initiatives and costs associated with greenhouse gas emissions from the electric sector. It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

In keeping with these findings, the European Union has adopted an objective of keeping global surface temperature increases to 2 degrees centigrade above pre-industrial levels. The EU Environment Council concluded in 2005 that this goal is likely to require emissions reductions of 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050.

In other words, incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates, but it does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

1. Introduction

Climate change is not only an "environmental" issue. It is at the confluence of energy and environmental policy, posing challenges to national security, economic prosperity, and national infrastructure. Many states do not require greenhouse gas reductions, nor do we yet have a federal policy requiring greenhouse gas reductions in the United States; thus many policy makers and corporate decision-makers in the electric sector may be tempted to consider climate change policy a hazy future possibility rather than a current factor in resource decisions. However, such a "wait and see" approach is imprudent for resource decisions with horizons of more than a few years. Scientific developments, policy initiatives at the local, state, and federal level, and actions of corporate leaders, all indicate that climate change policy will affect the electric sector – the question is not "whether" but "when," and in what magnitude.

Attention to global warming and its potential environmental, economic, and social impacts has rapidly increased over the past few years, adding to the pressure for comprehensive climate change policy in the United States The April 3, 2006 edition of TIME Magazine reports the results of a new survey conducted by TIME, ABC News and Stanford University which reveals that more than 80 percent of Americans believe global warming is occurring, while nearly 90 percent are worried that warming presents a serious problem for future generations. The poll reveals that 75 percent would like the US government, US businesses, and the American people to take further action on global warming in the next year.[3]

In the past several years, climate change has emerged as a significant financial risk for companies. A 2002 report from the investment community identifies climate change as representing a potential multi-billion dollar risk to a variety of US businesses and industries.[4] Addressing climate change presents particular risk and opportunity to the electric sector. Because the electric sector (and associated emissions) continue to grow, and because controlling emissions from large point sources (such as power plants) is easier, and often cheaper, than small disparate sources (like automobiles), the electric sector is likely to be a prime component of future greenhouse gas regulatory scenarios. The report states that "climate change clearly represents a major strategic issue for the electric utilities industry and is of relevance to the long-term evolution of the industry and possibly the survival of individual companies." Risks to electric companies include the following:

- Cost of reducing greenhouse gas emissions and cost of investment in new, cleaner power production technologies and methods;
- Higher maintenance and repair costs and reliability concerns due to more frequent weather extremes and climatic disturbance; and

[3] TIME/ABC News/Stanford University Poll, appearing in April 3, 2006 issue of Time Magazine.

[4] Innovest Strategic Value Advisors; "Value at Risk: Climate Change and the Future of Governance;" The Coalition for Environmentally Responsible Economies; April 2002.

- Growing pressure from customers and shareholders to address emissions contributing to climate change.[5]

A subsequent report, "Electric Power, Investors, and Climate Change: A Call to Action," presents the findings of a diverse group of experts from the power sector, environmental and consumer groups, and the investment community.[6] Participants in this dialogue found that greenhouse gas emissions, including carbon dioxide emissions, will be regulated in the United States; the only remaining issue is when and how. Participants also agreed that regulation of greenhouse gases poses financial risks and opportunities for the electric sector. Managing the uncertain policy environment on climate change is identified as "one of a number of significant environmental challenges facing electric company executives and investors in the next few years as well as the decades to come."[7] One of the report's four recommendations is that investors and electric companies come together to quantify and assess the financial risks and opportunities of climate change.

In a 2003 report for the World Wildlife Fund, Innovest Strategic Advisors determined that climate policy is likely to have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities and other power plant owners.[8] The report found that, even under conservative scenarios, additional costs could exceed 10 percent of 2002 earnings, though there are also significant opportunities. While utilities and non-utility generation owners have many options to deal with the impact of increasing prices on CO_2 emissions, doing nothing is the worst option. The report concludes that a company's profits could even increase with astute resource decisions (including fuel switching or power plant replacement).

Increased CO_2 emissions from fossil-fired power plants will not only increase environmental damages and challenges to socio-economic systems; on an individual company level they will also increase the costs of complying with future regulations – costs that are likely to be passed on to all customers. Power plants built today can generate electricity for as long as 50 years or more into the future.[9]

As illustrated in the table below, factoring costs associated with future regulations of carbon dioxide has an impact on the costs of resources. Resources with higher CO_2 emissions have a higher CO_2 cost per megawatt-hour than those with lower emissions.

[5] Ibid., pages 45-48.

[6] CERES; "Electric Power, Investors, and Climate Change: A Call to Action;" September 2003.

[7] Ibid., p. 6

[8] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[9] Biewald et. al.; "A Responsible Electricity Future: An Efficient, Cleaner and Balanced Scenario for the US Electricity System;" prepared for the National Association of State PIRGs; June 11, 2004.

Table I.1. Comparison of CO_2 costs per MWh for Various Resources

Resource	Scrubbed Coal (Bit)	Scrubbed Coal (Sub)	IGCC	Combined Cycle	Source Notes
Size	600	600	550	400	1
CO_2 (lb/MMBtu)	205.45	212.58	205.45	116.97	2, 3
Heat Rate (Btu/kWh)	8844	8844	8309	7196	1
CO_2 Price (2005$/ton)	19.63	19.63	19.63	19.63	4
CO_2 Cost per MWh	$17.83	$18.45	$16.75	$8.26	

1 - From AEO 2006
2 - From EIA's Electric Power Annual 2004, page 76
3 - IGCC emission rate assumed to be the same as the bituminous scrubbed coal rate
4 - From Synapse's carbon emissions price forecast levelized from 2010-2040 at a 7.32% real discount rate

Many trends in this country show increasing pressure for a federal policy requiring greenhouse gas emissions reductions. Given the strong likelihood of future carbon regulation in the United States, the contributions of the power sector to our nation's greenhouse gas emissions, and the long lives of power plants, utilities and non-utility generation owners should include carbon cost in all resource evaluation and planning.

The purpose of this report is to identify a reasonable basis for anticipating the likely cost of future mandated carbon emissions reductions for use in long-term resource planning decisions.[10] Section 2 presents information on US carbon emissions. Section 3 describes recent scientific findings on climate change. Section 4 describes international efforts to address the threat of climate change. Section 5 summarizes various initiatives at the state, regional, and corporate level to address climate change. Finally, section 6 summarizes information that can form the basis for forecasts of carbon allowance prices; and provides a reasonable carbon allowance price forecast for use in resource planning and investment decisions in the electric sector.

2. Growing scientific evidence of climate change

In 2001 the Intergovernmental Panel on Climate Change issued its Third Assessment Report.[11] The report, prepared by hundreds of scientists worldwide, concluded that the earth is warming, that most of the warming over the past fifty years is attributable to human activities, and that average surface temperature of the earth is likely to increase

[10] This paper focuses on anticipating the cost of future emission reduction requirements. This paper does not address the determination of an "externality value" associated with greenhouse gas emissions. The externality value would include societal costs beyond those internalized into market costs through regulation. While this report refers to the ecological and socio-economic impacts of climate change, estimation of the external costs of greenhouse gas emissions is beyond the scope of this analysis.

[11] Intergovernmental Panel on Climate Change, *Third Assessment Report*, 2001.

between 1.4 and 5.8 degrees Centigrade during this century, with a wide range of impacts on the natural world and human societies.

Scientists continue to explore the possible impacts associated with temperature increase of different magnitudes. In addition, they are examining a variety of possible scenarios to determine how much the temperature is likely to rise if atmospheric greenhouse gas concentrations are stabilized at certain levels. The consensus in the international scientific community is that greenhouse gas emissions will have to be reduced significantly below current levels. This would correspond to levels much lower than those limits underlying our CO_2 price forecasts. In 2001 the Intergovernmental Panel on Climate Change reported that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to keep global warming in the vicinity of a 2-3 degree centigrade temperature increase.[12]

Since 2001 the evidence of climate change, and human contribution to climate change, is even more compelling. In June 2005 the National Science Academies from eleven major nations, including the United States, issued a Joint Statement on a Global Response to Climate Change.[13] Among the conclusions in the statement were that

- Significant global warming is occurring;
- It is likely that most of the warming in recent decades can be attributed to human activities;
- The scientific understanding of climate change is now sufficiently clear to justify nations taking prompt action;
- Action taken now to reduce significantly the build-up of greenhouse gases in the atmosphere will lessen the magnitude and rate of climate change;
- The Joint Academies urge all nations to take prompt action to reduce the causes of climate change, adapt to its impacts and ensure that the issue is included in all relevant national and international strategies.

There is increasing concern in the scientific community that the earth may be more sensitive to global warming than previously thought. Increasing attention is focused on understanding and avoiding dangerous levels of climate change. A 2005 Scientific Symposium on Stabilization of Greenhouse Gases reached the following conclusions:[14]

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[12] IPCC, *Climate Change 2001: Synthesis Report*, Fourth Volume of the IPCC Third Assessment Report. IPCC 2001. Question 6.

[13] *Joint Science Academies' Statement: Global Response to Climate Change*, National Academies of Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, United Kingdom, and United States, June 7, 2005.

[14] UK Department of Environment, Food, and Rural Affairs, *Avoiding Dangerous Climate Change – Scientific Symposium on Stabilization of Greenhouse Gases, February 1-3, 2005 Exeter, U.K. Report of the International Scientific Steering Committee*, May 2005. *http://www.stabilisation2005.com/Steering_Commitee_Report.pdf*

- There is greater clarity and reduced uncertainty about the impacts of climate change across a wide range of systems, sectors and societies. In many cases the risks are more serious than previously thought.
- Surveys of the literature suggest increasing damage if the globe warms about 1 to 3^0C above current levels. Serious risk of large scale, irreversible system disruption, such as reversal of the land carbon sink and possible de-stabilisation of the Antarctic ice sheets is more likely above 3^0C.
- Many climate impacts, particularly the most damaging ones, will be associated with an increased frequency or intensity of extreme events (such as heat waves, storms, and droughts).
- Different models suggest that delaying action would require greater action later for the same temperature target and that even a delay of 5 years could be significant. If action to reduce emissions is delayed by 20 years, rates of emission reduction may need to be 3 to 7 times greater to meet the same temperature target.

As scientific evidence of climate change continues to emerge, including unusually high temperatures, increased storm intensity, melting of the polar icecaps and glaciers worldwide, coral bleaching, and sea level rise, pressure will continue to mount for concerted governmental action on climate change.[15]

3. US carbon emissions

The United States contributes more than any other nation, by far, to global greenhouse gas emissions on both a total and a per capita basis. The United States contributes 24 percent of the world CO_2 emissions from fossil fuel consumption, but has only 4.6 percent of the population. According to the International Energy Agency, 80 percent of 2002 global energy-related CO_2 emissions were emitted by 22 countries – from all world regions, 12 of which are OECD countries. These 22 countries also produced 80 percent of the world's 2002 economic output (GDP) and represented 78 percent of the world's Total Primary Energy Supply.[16] Figure 3.1 shows the top twenty carbon dioxide emitters in the world.

[15] Several websites provide summary information on climate change science including www.ipcc.org www.nrdc.org, www.ucsusa.org, and www.climateark.org.

[16] International Energy Agency, "CO_2 from Fuel Combustion – Fact Sheet," 2005

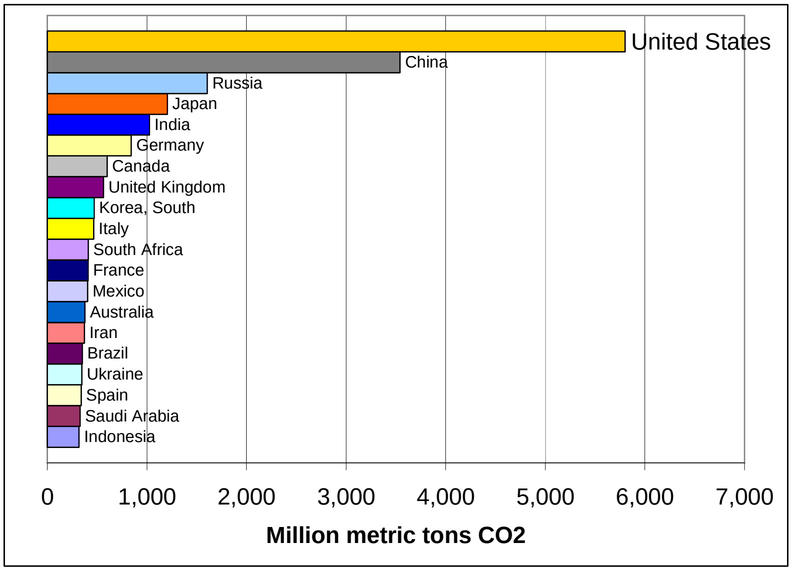

Figure 3.1. Top Worldwide Emitters of Carbon Dioxide in 2003

Source: Data from EIA Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2003, July 11, 2005

Emissions in this country in 2004 were roughly divided among three sectors: transportation (1,934 million metric tons CO_2), electric generation (2,299 million metric tons CO_2), and other (which includes commercial and industrial heat and process applications – 1,673 million metric tons CO_2). These emissions, largely attributable to the burning of fossil fuels, came from combustion of oil (44%), coal (35.4%), and natural gas (20.4%). Figure 3.2 shows emissions from the different sectors, with the electric sector broken out by fuel source.

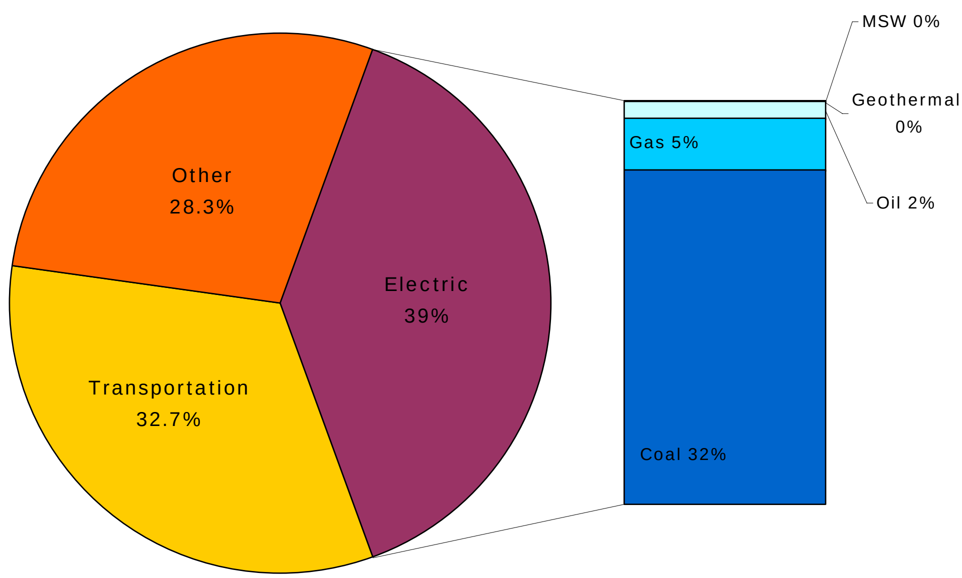

Figure 3.2. US CO_2 Emissions by Sector in 2004

Source: Data from EIA Emissions of Greenhouse Gases in the United States 2004, December 2005

Recent analysis has shown that in 2004, power plant CO_2 emissions were 27 percent higher than they were in 1990.[17] US greenhouse gas emissions per unit of Gross Domestic Product (GDP) fell from 677 metric tons per million 2000 constant dollars of GDP (MTCO2e/$Million GDP) in 2003 to 662 MTCO2e /$Million GDP in 2004, a decline of 2.1 percent.[18] However, while the carbon intensity of the US economy (carbon emissions per unit of GDP) fell by 12 percent between 1991 and 2002, the carbon intensity of the electric power sector held steady.[19] This is because the carbon efficiency gains from the construction of efficient and relatively clean new natural gas plants have been offset by increasing reliance on existing coal plants. Since federal acid rain legislation was enacted in 1990, the average rate at which existing coal plants are operated increased from 61 percent to 72 percent. Power plant CO_2 emissions are concentrated in states along the Ohio River Valley and in the South. Five states – Indiana, Ohio, Pennsylvania, Texas, and West Virginia – are the source of 30 percent of the electric power industry's NO_x and CO_2 emissions, and nearly 40 percent of its SO_2 and mercury emissions.

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[17] EIA, "Emissions of Greenhouse Gases in the United Sates, 2004;" Energy Information Administration; December 2005, xiii

[18] EIA *Emissions of Greenhouse Gases in the United States 2004*, December 2005.

[19] Goodman, Sandra; "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2002;" CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG); April 2004. An updated "Benchmarking Study" has been released: Goodman, Sandra and Walker, Michael. "Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the US - 2004." CERES, Natural Resources Defense Council (NRDC), and Public Service Enterprise Group Incorporated (PSEG). April 2006.

4. Governments worldwide have agreed to respond to climate change by reducing greenhouse gas emissions

The prospect of global warming and associated climate change has spurred one of the most comprehensive international treaties on environmental issues.[20] The 1992 United Nations Framework Convention on Climate Change has almost worldwide membership; and, as such, is one of the most widely supported of all international environmental agreements.[21] President George H.W. Bush signed the Convention in 1992, and it was ratified by Congress in the same year. In so doing, the United States joined other nations in agreeing that "The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities."[22] Industrialized nations, such as the United States, and Economies in Transition, known as Annex I countries in the UNFCCC, agree to adopt climate change policies to reduce their greenhouse gas emissions.[23] Industrialized countries that were members of the Organization for Economic Cooperation and Development (OECD) in 1992, called Annex II countries, have the further obligation to assist developing countries with emissions mitigation and climate change adaptation.

Following this historic agreement, most Parties to the UNFCCC adopted the Kyoto Protocol on December 11, 1997. The Kyoto Protocol supplements and strengthens the Convention; the Convention continues as the main focus for intergovernmental action to combat climate change. The Protocol establishes legally-binding targets to limit or reduce greenhouse gas emissions.[24] The Protocol also includes various mechanisms to cut emissions reduction costs. Specific rules have been developed on emissions sinks, joint implementation projects, and clean development mechanisms. The Protocol envisions a long-term process of five-year commitment periods. Negotiations on targets for the second commitment period (2013-2017) are beginning.

The Kyoto targets are shown below, in Table 4.1. Only Parties to the Convention that have also become Parties to the Protocol (i.e. by ratifying, accepting, approving, or acceding to it), are bound by the Protocol's commitments, following its entry into force in

[20] For comprehensive information on the UNFCC and the Kyoto Protocol, see UNFCC, "Caring for Climate: a guide to the climate change convention and the Kyoto Protocol," issued by the Climate Change Secretariat (UNFCC) Bonn, Germany. 2003. This and other publications are available at the UNFCCC's website: http://unfccc.int/.

[21] The First World Climate Conference was held in 1979. In 1988, the World Meteorological Society and the United Nations Environment Programme created the Intergovernmental Panel on Climate Change to evaluate scientific information on climate change. Subsequently, in 1992 countries around the world, including the United States, adopted the United Nations Framework Convention on Climate Change.

[22] From Article 3 of the United Nations Framework Convention on Climate Change, 1992.

[23] One of obligations of the United States and other industrialized nations is to a National Report describing actions it is taking to implement the Convention

[24] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

February 2005.[25] The individual targets for Annex I Parties add up to a total cut in greenhouse-gas emissions of at least 5 percent from 1990 levels in the commitment period 2008-2012.

Only a few industrialized countries have not signed the Kyoto Protocol; these countries include the United States, Australia, and Monaco. Of these, the United States is by far the largest emitter with 36.1 percent of Annex I emissions in 1990; Australia and Monaco were responsible for 2.1 percent and less than 0.1 percent of Annex I emissions, respectively. The United States did not sign the Kyoto protocol, stating concerns over impacts on the US economy and absence of binding emissions targets for countries such as India and China. Many developing countries, including India, China and Brazil have signed the Protocol, but do not yet have emission reduction targets.

In December 2005, the Parties agreed to final adoption of a Kyoto "rulebook" and a two-track approach to consider next steps. These next steps will include negotiation of new binding commitments for Kyoto's developed country parties, and, a nonbinding "dialogue on long-term cooperative action" under the Framework Convention.

Table 4.1. Emission Reduction Targets Under the Kyoto Protocol[26]

Country	**Target**: change in emissions from 1990** levels by 2008/2012
EU-15*, Bulgaria, Czech Republic, Estonia, Latvia, Liechtenstein, Lithuania, Monaco, Romania, Slovakia, Slovenia, Switzerland	-8%
United States***	-7%
Canada, Hungary, Japan, Poland	-6%
Croatia	-5%
New Zealand, Russian Federation, Ukraine	0
Norway	+1%
Australia***	+8%
Iceland	+10%

** The EU's 15 member States will redistribute their targets among themselves, as allowed under the Protocol. The EU has already reached agreement on how its targets will be redistributed.*
*** Some Economies In Transition have a baseline other than 1990.*
**** The United States and Australia have indicated their intention not to ratify the Kyoto Protocol.*

As the largest single emitter of greenhouse gas emissions, and as one of the only industrialized nations not to sign the Kyoto Protocol, the United States is under significant international scrutiny; and pressure is building for the United States to take more initiative in addressing the emerging problem of climate change. In 2005 climate change was a priority at the G8 Summit in Gleneagles, with the G8 leaders agreeing to "act with resolve and urgency now" on the issue of climate change.[27] The leaders

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[25] Entry into force required 55 Parties to the Convention to ratify the Protocol, including Annex I Parties accounting for 55 percent of that group's carbon dioxide emissions in 1990. This threshold was reached when Russia ratified the Protocol in November 2004. The Protocol entered into force February 16, 2005.

[26] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[27] G8 Leaders, *Climate Change, Clean Energy, and Sustainable Development*, Political Statement and Action Plan from the G8 Leaders' Communiqué at the G8 Summit in Gleneagles U.K., 2005. Available

reached agreement that greenhouse gas emissions should slow, peak and reverse, and that the G8 nations must make "substantial cuts" in greenhouse gas emissions. They also reaffirmed their commitment to the UNFCCC and its objective of stabilizing greenhouse gas concentrations in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate system.

The EU has already adopted goals for emissions reductions beyond the Kyoto Protocol. The EU has stated its commitment to limiting global surface temperature increases to 2 degrees centigrade above pre-industrial levels.[28] The EU Environment Council concluded in 2005 that to meet this objective in an equitable manner, developed countries should reduce emissions 15-30% below 1990 levels by 2020, and 60-80% below 1990 levels by 2050. A 2005 report from the European Environment Agency concluded that a 2 degree centigrade temperature increase was likely to require that global emissions increases be limited at 35% above 1990 levels by 2020, with a reduction by 2050 of between 15 and 50% below 1990 levels.[29] The EU has committed to emission reductions of 20-30% below 1990 levels by 2020, and reduction targets for 2050 are still under discussion.[30]

5. Legislators, state governmental agencies, shareholders, and corporations are working to reduce greenhouse gas emissions from the United States

There is currently no mandatory federal program requiring greenhouse gas emission reductions. Nevertheless, various federal legislative proposals are under consideration, and President Bush has acknowledged that humans are contributing to global warming. Meanwhile, state and municipal governments (individually and in cooperation), are leading the development and design of climate policy in the United States. Simultaneously, companies in the electric sector, acting on their own initiative or in compliance with state requirements, are beginning to incorporate future climate change policy as a factor in resource planning and investment decisions.

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at: http://www.g8.gov.uk/servlet/Front?pagename=OpenMarket/Xcelerate/ShowPage&c=Page&cid=1094235520309

[28] Council of the European Union, *Information Note – Brussels March 10, 2005.* http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

[29] European Environment Agency, *Climate Change and a European Low Carbon Energy System*, 2005. EEA Report No 1/2005. ISSN 1725-9177. http://reports.eea.europa.eu/eea_report_2005_1/en/Climate_change-FINAL-web.pdf

[30] Ibid; and European Parliament Press Release "Winning the Battle Against Climate Change" November 17, 2005. http://www.europarl.europa.eu/news/expert/infopress_page/064-2439-320-11-46-911-20051117IPR02438-16-11-2005-2005-false/default_en.htm

5.1 Federal initiatives

With ratification of the United Nations Framework Convention on Climate Change in 1992, the United States agreed to a goal of "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[31] To date, the Federal Government in the United States has not required greenhouse gas emission reductions, and the question of what constitutes a dangerous level of human interference with the climate system remains unresolved. However, legislative initiatives for a mandatory market-based greenhouse gas cap and trade program are under consideration.

To date, the Bush Administration has relied on voluntary action. In July 2005, President Bush changed his public position on causation, acknowledging that the earth is warming and that human actions are contributing to global warming.[32] That summer, the Administration launched a new climate change pact between the United States and five Asian and Pacific nations aimed at stimulating technology development and inducing private investments in low-carbon and carbon-free technologies. The Asia-Pacific Partnership on Clean Development and Climate – signed by Australia, China, India, Japan, South Korea and the United States – brings some of the largest greenhouse gas emitters together; however its reliance on voluntary measures reduces its effectiveness.

The legislative branch has been more active in exploring mandatory greenhouse gas reduction policies. In June 2005, the Senate passed a sense of the Senate resolution recognizing the need to enact a US cap and trade program to slow, stop and reverse the growth of greenhouse gases. [33]

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[31] The UNFCC was signed by President George H. Bush in 1992 and ratified by the Senate in the same year.

[32] "Bush acknowledges human contribution to global warming; calls for post-Kyoto strategy." Greenwire, July 6, 2005.

[33] US Senate, *Sense of the Senate Resolution on Climate Change,* US Senate Resolution 866; June 22, 2005. Available at: http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.Detail&PressRelease_id=234715&Month=6&Year=2005&Party=0

Sense of the Senate Resolution – June 2005

> It is the sense of the Senate that, before the end of the 109th Congress, Congress should enact a comprehensive and effective national program of mandatory, market-based limits on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that
>
> (1) will not significantly harm the United States economy; and
>
> (2) will encourage complementary action by other nations that are major trading partners and key contributors to global emissions.

This Resolution built upon previous areas of agreement in the Senate, and provides a foundation for future agreement on a cap and trade program. On May 10, 2006 the House Appropriations Committee adopted very similar language supporting a mandatory cap on greenhouse gas emissions in a non-binding amendment to a 2007 spending bill.[34]

Several mandatory emissions reduction proposals have been introduced in Congress. These proposals establish emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. Federal proposals that would require greenhouse gas emission reductions are summarized in Table 5.1, below.

[34] "House appropriators OK resolution on need to cap emissions," Greenwire, May 10, 2005.

Table 5.1. Summary of Federal Mandatory Emission Reduction Proposals

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Sen. Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants >15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO2) starting in 2009, 2001 levels (2.454 billion tons CO2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants >25 MW
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Not available

Landmark legislation that would regulate carbon, the Climate Stewardship Act (S.139), was introduced by Senators McCain and Lieberman in 2003, and received 43 votes in the Senate. A companion bill was introduced in the House by Congressmen Olver and Gilchrest. As initially proposed, the bill created an economy-wide two-step cap on greenhouse gas emissions. The bill was reintroduced in the 109th Congress on February 10, 2005; the revised Climate Stewardship Act, SA 2028, would create a national cap and trade program to reduce CO_2 to year 2000 emission levels over the period 2010 to 2015. Other legislative initiatives on climate change were also under consideration in the spring of 2005, including a proposal by Senator Jeffords (D-VT) to cap greenhouse gas emissions from the electric sector (S. 150), and an electric sector four-pollutant bill from Senator Carper (D-DE) (S. 843).

In 2006, the Senate appears to be moving beyond the question of whether to regulate greenhouse gas emissions, to working out the details of how to regulate greenhouse gas emissions. Senators Domenici (R-NM) and Bingaman (D-NM) are working on bi-partisan legislation based on the recommendations of the National Commission on Energy Policy (NCEP). The NCEP – a bipartisan group of energy experts from industry, government, labor, academia, and environmental and consumer groups – released a consensus strategy in December 2004 to address major long-term US energy challenges. Their report recommends a mandatory economy-wide tradable permits program to limit GHG. Costs would be capped at $7/metric ton of CO_2 equivalent in 2010 with the cap rising 5 percent annually.[35] The Senators are investigating the details of creating a mandatory economy-wide cap and trade system based on mandatory reductions in greenhouse gas intensity (measured in tons of emissions per dollar of GDP). In the spring of 2006, the Senate Energy and Natural Resources Committee held hearings to develop the details of a proposal.[36] During these hearings many companies in the electric power sector, such as Exelon, Duke Energy, and PNM Resources, expressed support for a mandatory national greenhouse gas cap and trade program.[37]

Two other proposals in early 2006 have added to the detail of the increasingly lively discussion of federal climate change strategies. Senator Feinstein (D-CA) issued a proposal for an economy-wide cap and trade system in order to further spur debate on the issue.[38] Senator Feinstein's proposal would cap emissions and seek reductions at levels largely consistent with the original McCain-Lieberman proposal. The most recent proposal to be added to the discussion is one by Reps. Tom Udall (D-NM) and Tom Petri (R-WI). The proposal includes a market-based trading system with an emissions cap to be established by the EPA about three years after the bill becomes law. The bill includes provisions to spur new research and development by setting aside 25 percent of the trading system's allocations for a new Energy Department technology program, and 10 percent of the plan's emission allowances to the State Department for spending on zero-carbon and low-carbon projects in developing nations. The bill would regulate greenhouse gas emissions at "upstream" sources such as coal mines and oil imports. Also,

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[35] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, pages 19-29.

[36] The Senators have issued a white paper, inviting comments on various aspects of a greenhouse gas regulatory system. See, Senator Pete V. Domenici and Senator Jeff Bingaman, "Design Elements of a Mandatory Market-based Greenhouse Gas Regulatory System," issued February 2, 2006.

[37] All of the comments submitted to the Senate Energy and Natural Resources Committee are available at: http://energy.senate.gov/public/index.cfm?FuseAction=IssueItems.View&IssueItem_ID=38

[38] Letter of Senator Feinstein announcing "Strong Economy and Climate Protection Act of 2006," March 20, 2006.

it would establish a "safety valve" initially limiting the price of a ton of carbon dioxide emission to $25.[39]

Figure 5.1 illustrates the anticipated emissions trajectories from the economy-wide proposals - though the most recent proposal in the House is not included due to its lack of a specified emissions cap.

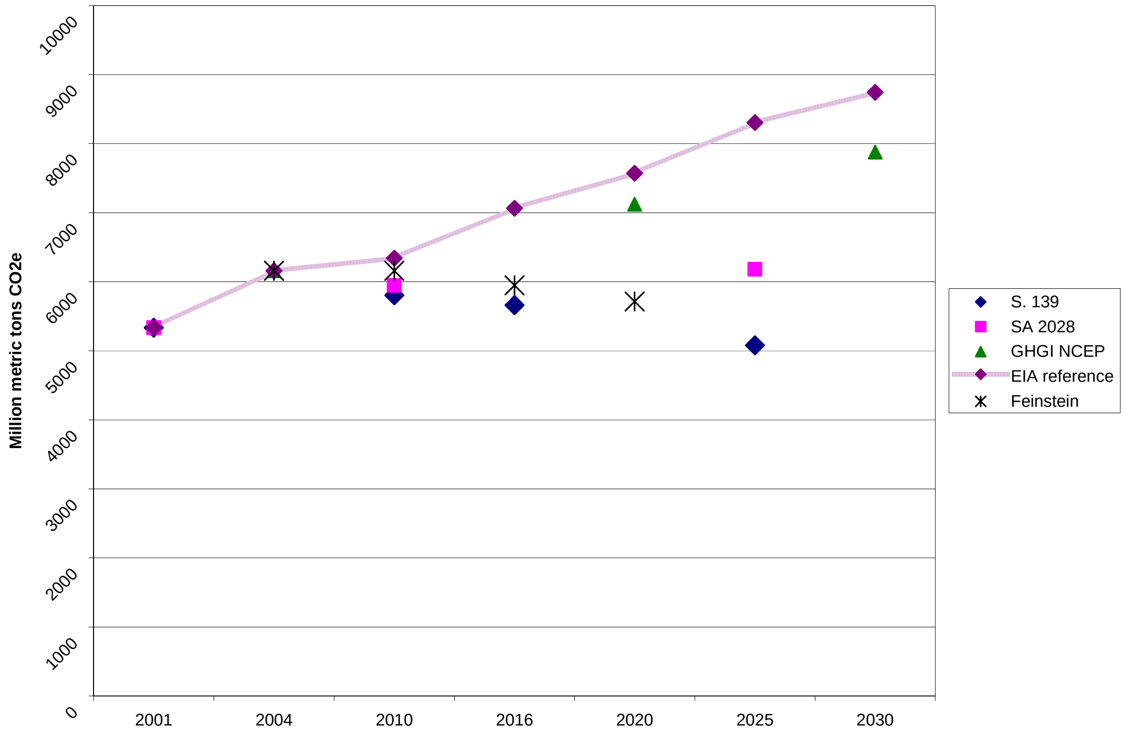

Figure 5.1. Emission Trajectories of Proposed Federal Legislation

Anticipated emissions trajectories from federal proposals for economy-wide greenhouse gas cap and trade proposals (McCain Lieberman S.139 Climate Stewardship Act 2003, McCain-Lieberman SA 2028 Climate Stewardship Act 2005, National Commission on Energy Policy greenhouse gas emissions intensity cap, and Senator Feinstein's Strong Economy and Climate Protection Act). EIA Reference trajectory is a composite of Reference cases in EIA analyses of the above policy proposals.

The emissions trajectories contained in the proposed federal legislation are in fact quite modest compared with emissions reductions that are anticipated to be necessary to achieve stabilization of atmospheric concentrations of greenhouse gases at levels that correspond to temperature increase of about 2 degrees centigrade. Figure 5.2 compares various emission reduction trajectories and goals in relation to a 1990 baseline. US federal proposals, and even Kyoto Protocol reduction targets, are small compared with the current EU emissions reduction target for 2020, and emissions reductions that will ultimately be necessary to cope with global warming.

[39] Press release, "Udall and Petri introduce legislation to curb global warming," March 29, 2006.

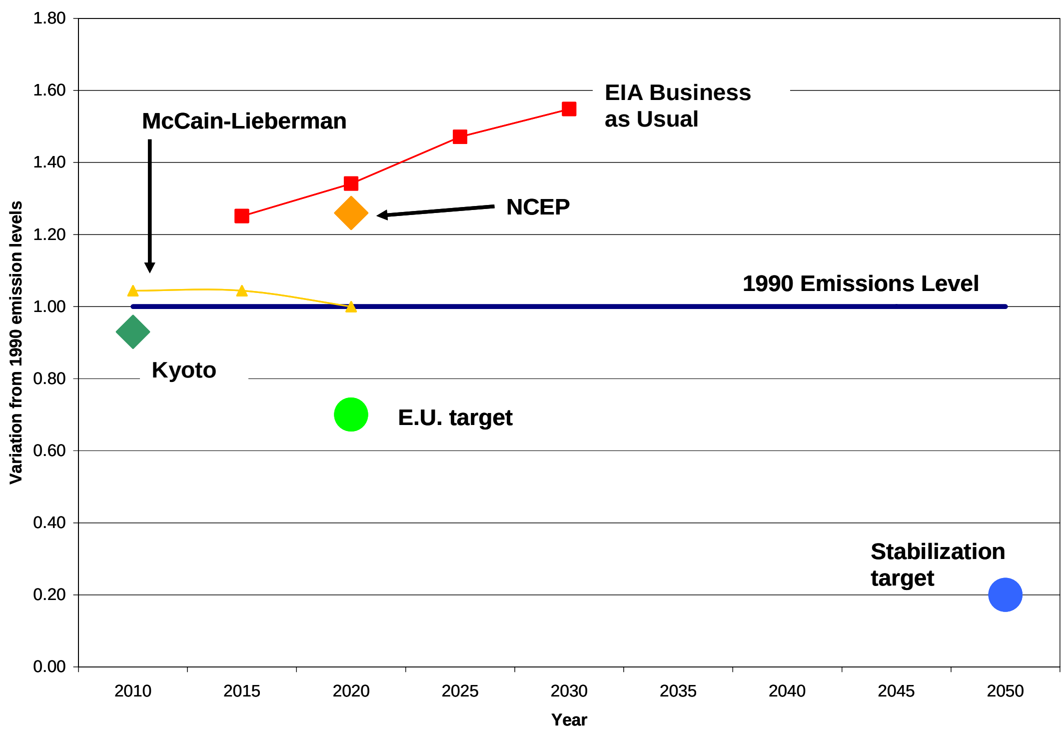

Figure 5.2 Comparison of Emission Reduction Goals

Figure compares emission reduction goals with 1990 as the baseline. Kyoto Protocol target for the United States would have been 7% below 1990 emissions levels. EU target is 20-30% below 1990 emissions levels. Stabilization target represents a reduction of 80% below 1990 levels. While there is no international agreement on the level at which emissions concentrations should be stabilized, and the emissions trajectory to achieve a stabilization target is not determined, reductions of 80% below 1990 levels indicates the magnitude of emissions reductions that are currently anticipated to be necessary.

As illustrated in the above figure, long term emission reduction goals are likely to be much more aggressive than those contained in federal policy proposals to date. Thus it is likely that cost projections will increase as targets become more stringent.

While efforts continue at the federal level, some individual states and regions are adopting their own greenhouse gas mitigation policies. Many corporations are also taking steps, on their own initiative, pursuant to state requirements, or under pressure from shareholder resolutions, in anticipation of mandates to reduce emissions of greenhouse gases. These efforts are described below.

5.2 State and regional policies

Many states across the country have not waited for federal policies and are developing and implementing climate change-related policies that have a direct bearing on resource choices in the electric sector. States, acting individually, and through regional coordination, have been the leaders on climate change policies in the United States. Generally, policies that individual states adopt fall into the following categories: (1) Direct policies that require specific emission reductions from electric generation sources; and (2) Indirect policies that affect electric sector resource mix such as through promoting low-emission electric sources; (3) Legal proceedings; or (4) Voluntary programs including educational efforts and energy planning.

Table 5.2. Summary of Individual State Climate Change Policies

Type of Policy	Examples
Direct • Power plant emission restrictions (e.g. cap or emission rate) • New plant emission restrictions • State GHG reduction targets • Fuel/generation efficiency	 • MA, NH • OR, WA • CT, NJ, ME, MA, CA, NM, NY, OR, WA • CA vehicle emissions standards to be adopted by CT, NY, ME, MA, NJ, OR, PA, RI, VT, WA
Indirect (clean energy) • Load-based GHG cap • GHG in resource planning • Renewable portfolio standards • Energy efficiency/renewable charges and funding; energy efficiency programs • Net metering, tax incentives	 • CA • CA, WA, OR, MT, KY • 22 states and D.C. • More than half the states • 41 states
Lawsuits • States, environmental groups sue EPA to determine whether greenhouse gases can be regulated under the Clean Air Act • States sue individual companies to reduce GHG emissions	 • States include CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI • NY, CT, CA, IA, NJ, RI, VT, WI
Climate change action plans	• 28 states, with NC and AZ in progress

Several states have adopted direct policies that require specific emission reductions from specific electric sources. Some states have capped carbon dioxide emissions from sources in the state (through rulemaking or legislation), and some restrict emissions from new sources through offset requirements. The California Public Utilities Commission recently stated that it will develop a load-based cap on greenhouse gas emissions in the electric sector. Table 5.3 summarizes these direct policies.

Table 5.3. State Policies Requiring GHG Emission Reductions From Power Plants

Program type	State	Description	Date	Source
Emissions limit	MA	Department of Environmental Protection decision capping GHG emissions, requiring 10 percent reduction from historic baseline	April 1, 2001	310 C.M.R. 7.29
Emissions limit	NH	NH Clean Power Act	May 1, 2002	HB 284
Emissions limit on new plants	OR	Standard for CO_2 emissions from new electricity generating facilities (base-load gas, and non-base load generation)	Updated September 2003	OR Admin. Rules, Ch. 345, Div 24
Emissions limit on new plants	WA	Law requiring new power plants to mitigate emissions or pay for a portion of emissions	March 1, 2004	RCW 80.70.020
Load-based emissions limit	CA	Public Utilities Commission decision stating intent to establish load-based cap on GHG emissions	February 17, 2006	D. 06-02-032 in docket R. 04-04-003

Several states require that integrated utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement. Some of the states such as California require that companies use a specific value, while other states require generally that companies consider the risk of future regulation in their planning process. Table 5.4 summarizes state requirements for consideration of greenhouse gas emissions in the planning process.

Table 5.4. Requirements for Consideration of GHG Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787
GHG in CON	MN	Law requires that proposed non-renewable generating facilities consider the risk of environmental regulation over expected useful life of the facility	2005	Minn. Stat. §216B.243 subd. 3(12)

In June 2005 both California and New Mexico adopted ambitious greenhouse gas emission reduction targets that are consistent with current scientific understanding of the emissions reductions that are likely to be necessary to avoid dangerous human interference with the climate system. In California, an Executive Order directs the state to reduce GHG emissions to 2000 levels by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050. In New Mexico, an Executive Order established statewide goals to reduce New Mexico's total greenhouse gas emissions to 2000 levels by 2012, 10 percent below those levels by 2020, and 75 percent below 2000 levels by 2050. In September 2005 New Mexico also adopted a legally binding agreement to lower emissions through the Chicago Climate Exchange. More broadly, to date at least twenty-eight states have developed Climate Action Plans that include statewide plans for addressing climate change issues. Arizona and North Carolina are in the process of developing such plans.

States are also pursuing other approaches. For example, in November 2005, the governor of Pennsylvania announced a new program to modernize energy infrastructure through replacement of traditional coal technology with advanced coal gasification technology. Energy Deployment for a Growing Economy allows coal plant owners a limited time to continue to operate without updated emissions technology as long as they make a commitment by 2007 to replace older plants with IGCC by 2013.[40] In September of 2005 the North Carolina legislature formed a commission to study and make recommendations on voluntary GHG emissions controls. In October 2005, New Jersey designated carbon dioxide as a pollutant, a necessary step for the state's participation in the Regional Greenhouse Gas Initiative (described below).[41]

Finally, states are pursuing legal proceedings addressing greenhouse gas emissions. Many states have participated in one or several legal proceedings to seek greenhouse gas emission reductions from some of the largest polluting power plants. Some states have also sought a legal determination regarding regulation of greenhouse gases under the Clean Air Act. The most recent case involves 10 states and two cities suing the Environmental Protection Agency to determine whether greenhouse gases can be regulated under the Clean Air Act.[42] The states argue that EPA's recent emissions standards for new sources should include carbon dioxide since carbon dioxide, as a major contributor to global warming, harms public health and welfare, and thus falls within the scope of the Clean Air Act.

While much of the focus to date has been on the electric sector, states are also beginning to address greenhouse gas emissions in other sectors. For example, California has

[40] Press release, "Governor Rendell's New Initiative, 'The Pennsylvania EDGE,' Will Put Commonwealth's Energy Resources to Work to Grow Economy, Clean Environment," November 28, 2005.

[41] Press release, "Codey Takes Crucial Step to Combat Global Warming," October 18, 2005.

[42] The states are CA, CT, ME, MA, NM, NY, OR, RI, VT, and WI. New York City and Washington D.C., as well as the Natural Resources Defense Council, the Sierra Club, and Environmental Defense. New York State Attorney General Eliot Spitzer, "States Sue EPA for Violating Clean Air Act and Failing to Act on Global Warming," press release, April 27, 2006.

adopted emissions standards for vehicles that would restrict carbon dioxide emissions. Ten other states have decided to adopt California's vehicle emissions standards.

States are not just acting individually; there are several examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g. Southwest governors, and Midwestern legislators) to development of a regional cap and trade program through the Regional Greenhouse Gas Initiative in the Northeast. These regional activities are summarized in Table 5.5, below.

Table 5.5. Regional Climate Change Policy Initiatives

Program type	State	Description	Date	Source
Regional GHG reduction Plan	CT, DE, MD, ME, NH, NJ, NY, VT	Regional Greenhouse Gas Initiative capping GHG emissions in the region and establishing trading program	MOU December 20, 2005, Model Rule February 2006	Memorandum of Understanding and Model Rule
Regional GHG reduction Plan	CA, OR, WA	West Coast Governors' Climate Change Initiative	September 2003, Staff report November 2004	Staff Report to the Governors
Regional GHG coordination	NM, AZ	Southwest Climate Change Initiative	February 28, 2006	Press release
Regional legislative coordination	IL, IA, MI, MN, OH, WI	Legislators from multiple states agree to coordinate regional initiatives limiting global warming pollution	February 7, 2006	Press release
Regional Climate Change Action Plan	New England, Eastern Canada	New England Governors and Eastern Canadian Premiers agreement for comprehensive regional Climate Change Action Plan. Targets are to reduce regional GHG emissions to 1990 levels by 2010, at least 10 percent below 1990 levels by 2020, and long-term reduction consistent with elimination of dangerous threat to climate (75-85 percent below current levels).	August, 2001	Memorandum of Understanding

Seven Northeastern and Mid-Atlantic states (CT, DE, ME, NH, NJ, NY, and VT) reached agreement in December 2005 on the creation of a regional greenhouse gas cap and trade program. The Regional Greenhouse Gas Initiative (RGGI) is a multi-year cooperative effort to design a regional cap and trade program initially covering CO_2 emissions from power plants in the region. Massachusetts and Rhode Island have actively participated in RGGI, but have not yet signed the agreement. Collectively, these states and Massachusetts and Rhode Island (which participated in RGGI negotiations) contribute 9.3 percent of total US CO_2 emissions and together rank as the fifth highest CO_2 emitter in the world. Maryland passed a law in April 2006 requiring participation in RGGI.[43] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process.[44]

The RGGI states have agreed to the following:

- Stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.
- Allocation of a minimum of 25 percent of allowances for consumer benefit and strategic energy purposes
- Certain offset provisions that increase flexibility to moderate price impacts
- Development of complimentary energy policies to improve energy efficiency, decrease the use of higher polluting electricity generation and to maintain economic growth.[45]

The states released a Model Rule in February 2006. The states must next consider adoption of rules consistent with the Model Rule through their regular legislative and regulatory policies and procedures.

Many cities and towns are also adopting climate change policies. Over 150 cities in the United States have adopted plans and initiatives to reduce emissions of greenhouse gases, setting emissions reduction targets and taking measures within municipal government operations. Climate change was a major issue at the annual US Conference of Mayors convention in June 2005, when the Conference voted unanimously to support a climate protection agreement, which commits cities to the goal of reducing emissions seven percent below 1990 levels by 2012.[46] World-wide, the Cities for Climate Protection Campaign (CCP), begun in 1993, is a global campaign to reduce emissions that cause climate change and air pollution. By 1999, the campaign had engaged more than 350 local governments in this effort, who jointly accounted for approximately seven percent of global greenhouse gas emissions.[47]All of these recent activities contribute to growing pressure within the United States to adopt regulations at a national level to reduce the emissions of greenhouse gases, particularly CO_2. This pressure is likely to increase over time as climate change issues and measures for addressing them become better

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[43] Maryland Senate Bill 154 *Healthy Air Act*, signed April 6, 2006.

[44] Information on this effort is available at www.rggi.org

[45] The MOU states "Each state will maintain and, where feasible, expand energy policies to decrease the use of less efficient or relatively higher polluting generation while maintaining economic growth. These may include such measures as: end-use efficiency programs, demand response programs, distributed generation policies, electricity rate designs, appliance efficiency standards and building codes. Also, each state will maintain and, where feasible, expand programs that encourage development of non-carbon emitting electric generation and related technologies." RGGI MOU, Section 7, December 20, 2005.

[46] the US Mayors Climate Protection Agreement, 2005. Information available at http://www.ci.seattle.wa.us/mayor/climate

[47] Information on the Cities for Climate Protection Campaign, including links to over 150 cities that have adopted greenhouse gas reduction measures, is available at http://www.iclei.org/projserv.htm#ccp

understood by the scientific community, by the public, the private sector, and particularly by elected officials.

5.3 Investor and corporate action

Several electric companies and other corporate leaders have supported the concept of a mandatory greenhouse gas emissions program in the United States. For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[48]

Similarly, in comments to the Senate Energy and Natural Resources Committee, the vice president of Exelon reiterated the company's support for a federal mandatory carbon policy, stating that "It is critical that we start now. We need the economic and regulatory certainty to invest in a low-carbon energy future."[49] Corporate leaders from other sectors are also increasingly recognizing climate change as a significant policy issue that will affect the economy and individual corporations. For example, leaders from Wal-Mart, GE, Shell, and BP, have all taken public positions supporting the development of mandatory climate change policies.[50]

In a 2004 national survey of electric generating companies in the United States, conducted by PA Consulting Group, about half the respondents believe that Congress will enact mandatory limits on CO_2 emissions within five years, while nearly 60 percent anticipate mandatory limits within the next 10 years. Respondents represented companies that generate roughly 30 percent of US electricity.[51] Similarly, in a 2005 survey of the North American electricity industry, 93% of respondents anticipate increased pressure to take action on global climate change.[52]

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[48] Paul Anderson, Chairman, Duke Energy, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," April 6, 2006 speech to CERES Annual Conference, at: http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf

[49] Elizabeth Moler, Exelon V.P., to the Senate Energy and Natural Resources Committee, April 4, 2006, quoted in Grist, http://www.grist.org/news/muck/2006/04/14/griscom-little/

[50] See, e.g., Raymond Bracy, V.P. for Corporate Affairs, Wal-Mart, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; David Slump, GE Energy, General Manager, Global Marketing, Comments to Senate Energy and Natural Resources Committee hearings on the design of CO2 cap-and-trade system, April 4, 2006; John Browne, CEO of BP, "Beyond Kyoto," Foreign Affairs, July/August 2004; Shell company website at www.shell.com.

[51] PA Consulting Group, "Environmental Survey 2004" Press release, October 22, 2004.

[52] GF Energy, "GF Energy 2005 Electricity Outlook" January 2005. However, it is interesting to note that climate ranked 11th among issues deemed important to individual companies.

Some investors and corporate leaders have taken steps to manage risk associated with climate change and carbon policy. Investors are gradually becoming aware of the financial risks associated with climate change, and there is a growing body of literature regarding the financial risks to electric companies and others associated with climate change. Many investors are now demanding that companies take seriously the risks associated with carbon emissions. Shareholders have filed a record number of global warming resolutions for 2005 for oil and gas companies, electric power producers, real estate firms, manufacturers, financial institutions, and auto makers.[53] The resolutions request financial risk disclosure and plans to reduce greenhouse gas emissions. Four electric utilities – AEP, Cinergy, TXU and Southern – have all released reports on climate risk following shareholder requests in 2004. In February 2006, four more US electric power companies in Missouri and Wisconsin also agreed to prepare climate risk reports.[54]

State and city treasurers, labor pension fund officials, and foundation leaders have formed the Investor Network on Climate Risk (INCR) which now includes investors controlling $3 trillion in assets. In 2005, the INCR issued "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," which discusses efforts to address climate risk since 2003 and identifies areas for further action. It urges institutional investors, fund managers, companies, and government policymakers to increase their oversight and scrutiny of the investment implications of climate change.[55] A 2004 report cites analysis indicating that carbon constraints affect market value – with modest greenhouse gas controls reducing the market capitalization of many coal-dependent US electric utilities by 5 to 10 percent, while a more stringent reduction target could reduce their market value 10 to 35 percent.[56] The report recommends, as one of the steps that company CEOs should pursue, integrating climate policy in strategic business planning to maximize opportunities and minimize risks.

Institutional investors have formed The Carbon Disclosure Project (CDP), which is a forum for institutional investors to collaborate on climate change issues. Its mission is to inform investors regarding the significant risks and opportunities presented by climate change; and to inform company management regarding the serious concerns of shareholders regarding the impact of these issues on company value. Involvement with the CDP tripled in about two and a half years, from $10 trillion under managements in

[53] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[54] "Four Electric Power Companies in Midwest Agree to Disclose Climate Risk," CERES press release February 21, 2006. Companies are Great Plains Energy Inc. in Kansas City, MO, Alliant Energy in Madison, WI, WPS Resources in Green Bay, WI and MGE Energy in Madison, WI.

[55] 2005 Institutional Investor Summit, "A New Call for Action: Managing Climate Risk and Capturing the Opportunities," May 10, 2005. The Final Report from the 2003 Institutional Investors Summit on Climate Risk, November 21, 2003 contains good summary information on risk associated with climate change.

[56] Cogan, Douglas G.; "Investor Guide to Climate Risk: Action Plan and Resource for Plan Sponsors, Fund Managers, and Corporations;" Investor Responsibility Research Center; July 2004 citing Frank Dixon and Martin Whittaker, "Valuing Corporate Environmental Performance: Innovest's Evaluation of the Electric Utilities Industry," New York, 1999.

Nov. 2003 to $31 trillion under management today.[57] The CDP released its third report in September 2005. This report continued the trend in the previous reports of increased participation in the survey, and demonstrated increasing awareness of climate change and of the business risks posed by climate change. CDP traces the escalation in scope and awareness – on behalf of both signatories and respondents – to an increased sense of urgency with respect to climate risk and carbon finance in the global business and investment community. [58]

Findings in the third CDP report included:

- More than 70% of FT500 companies responded to the CDP information request, a jump from 59% in CDP2 and 47% in CDP1.[59]
- More than 90% of the 354 responding FT500 companies flagged climate change as posing commercial risks and/or opportunities to their business.
- 86% reported allocating management responsibility for climate change.
- 80% disclosed emissions data.
- 63% of FT500 companies are taking steps to assess their climate risk and institute strategies to reduce greenhouse gas emissions.[60]

The fourth CDP information request (CDP4) was sent on behalf of 211 institutional investors with significant assets under management to the Chairmen of more than 1900 companies on February 1, 2006, including 300 of the largest electric utilities globally.

The California Public Employees' Retirement System (CalPERS) announced that it will use the influence made possible by its $183 billion portfolio to try to convince companies it invests in to release information on how they address climate change. The CalPERS board of trustees voted unanimously for the environmental initiative, which focuses on the auto and utility sectors in addition to promoting investment in firms with good environmental practices.[61]

Major financial institutions have also begun to incorporate climate change into their corporate policy. For example, Goldman Sachs and JP Morgan support mandatory market-based greenhouse gas reduction policies, and take greenhouse gas emissions into account in their financial analyses. Goldman Sachs was the first global investment bank to adopt a comprehensive environmental policy establishing company greenhouse gas

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[57] See: http://www.cdproject.net/aboutus.asp

[58] Innovest Strategic Value Advisors; "Climate Change and Shareholder Value In 2004," second report of the Carbon Disclosure Project; Innovest Strategic Value Advisors and the Carbon Disclosure Project; May 2004.

[59] FT 500 is the Financial Times' ranking of the top 500 companies ranked globally and by sector based on market capital.

[60] CDP press release, September 14, 2005. Information on the Carbon Disclosure Project, including reports, are available at: http://www.cdproject.net/index.asp.

[61] *Greenwire*, February 16, 2005

reduction targets and supporting a national policy to limit greenhouse gas emissions. [62] JP Morgan, Citigroup, and Bank of America have all adopted lending policies that cover a variety of project impacts including climate change.

Some CEOs in the electric industry have determined that inaction on climate change issues is not good corporate strategy, and individual electric companies have taken steps to reduce greenhouse gas emissions. Their actions represent increasing initiative in the electric industry to address the threat of climate change and manage risk associated with future carbon constraints. Recently, eight US-based utility companies have joined forces to create the "Clean Energy Group." This group's mission is to seek "national four-pollutant legislation that would, among other things… stabilize carbon emissions at 2001 levels by 2013."[63] The President of Duke Energy urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[64] Prior to its merger with Duke, Cinergy Corporation was vocal on its support of mandatory national carbon regulation. Cinergy established a target is to produce 5 percent below 2000 levels by 2010 – 2012. AEP adopted a similar target. FPL Group and PSEG are both aiming to reduce total emissions by 18 percent between 2000 and 2008.[65] A fundamental impediment to action on the part of electric generating companies is the lack of clear, consistent, national guidelines so that companies could pursue emissions reductions without sacrificing competitiveness.

While statements such as these are an important first step, they are only a starting point, and do not, in and of themselves, cause reductions in carbon emissions. It is important to keep in mind the distinction between policy statements and actions consistent with those statements.

6. Anticipating the cost of reducing carbon emissions in the electric sector

Uncertainty about the form of future greenhouse gas reduction policies poses a planning challenge for generation-owning entities in the electric sector, including utilities and non-utility generators. Nevertheless, it is not reasonable or prudent to assume in resource planning that there is no cost or financial risk associated with carbon dioxide emissions, or with other greenhouse gas emissions. There is clear evidence of climate change, federal legislation has been under discussion for the past few years, state and regional regulatory efforts are currently underway, investors are increasingly pushing for companies to address climate change, and the electric sector is likely to constitute one of

[62] Goldman Sachs Environmental Policy Framework, http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

[63] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[64] Paul M. Anderson Letter to Shareholders, March 15, 2005.

[65] Ibid.

the primary elements of any future regulatory plan. Analyses of various economy-wide policies indicate that a majority of emissions reductions will come from the electric sector. In this context and policy climate, utilities and non-utility generators must develop a reasoned assessment of the costs associated with expected emissions reductions requirements. Including this assessment in the evaluation of resource options enables companies to judge the robustness of a plan under a variety of potential circumstances.

This is particularly important in an industry where new capital stock usually has a lifetime of 50 or more years. An analysis of capital cycles in the electric sector finds that "external market conditions are the most significant influence on a firm's decision to invest in or decommission large pieces of physical capital stock.[66] Failure to adequately assess market conditions, including the potential cost increases associated with likely regulation, poses a significant investment risk for utilities. It would be imprudent for any company investing in plants in the electric sector, where capital costs are high and assets are long-lived, to ignore policies that are inevitable in the next five to twenty years. Likewise, it would be short-sighted for a regulatory entity to accept the valuation of carbon emissions at no cost.

Evidence suggests that a utility's overall compliance decisions will be more efficient if based on consideration of several pollutants at once, rather than addressing pollutants separately. For example, in a 1999 study EPA found that pollution control strategies to reduce emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury are highly inter-related, and that the costs of control strategies are highly interdependent.[67] The study found that the total costs of a coordinated set of actions is less than that of a piecemeal approach, that plant owners will adopt different control strategies if they are aware of multiple pollutant requirements, and that combined SO_2 and carbon emissions reduction options lead to further emissions reductions.[68] Similarly, in one of several studies on multi-pollutant strategies, the Energy Information Administration (EIA) found that using an integrated approach to NO_x, SO_2, and CO_2, is likely to lead to lower total costs than addressing pollutants one at a time.[69] While these studies clearly indicate that federal emissions policies should be comprehensive and address multiple pollutants, they also demonstrate the value of including future carbon costs in current resource planning activities.

There are a variety of sources of information that form a basis for developing a reasonable estimate of the cost of carbon emissions for utility planning purposes. Useful sources include recent market transactions in carbon markets, values that are currently being used in utility planning, and costs estimates based on scenario modeling of proposed federal legislation and the Regional Greenhouse Gas Initiative.

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[66] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[67] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[68] US EPA, *Briefing Report,* March 1999.

[69] EIA, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*. December 2000.

6.1 International market transactions

Implementation of the Kyoto Protocol has moved forward with great progress in recent years. Countries in the European Union (EU) are now trading carbon in the first international emissions market, the EU Emissions Trading Scheme (ETS), which officially launched on January 1, 2005. This market, however, was operating before that time – Shell and Nuon entered the first trade on the ETS in February 2003. Trading volumes increased steadily throughout 2004 and totaled approximately 8 million tons CO_2 in that year. [70]

Prices for current- and near-term EU allowances (2006-2007) escalated sharply in 2005, rising from roughly $11/ton CO_2 (9 euros/ton-CO_2) in the second half of 2004 and leveling off at about $36/ton CO_2 (28 euros/ton- CO_2) early in 2006. In March 2006, the market price for 2008 allowances hovered at around $32/ton CO_2 (25 euros/ton- CO_2).[71] Lower prices in late April resulted from several countries' announcements that their emissions were lower than anticipated. The EU member states will submit their carbon emission allocation plans for the period 2008-2012 in June. Market activity to date in the EU Emissions trading system illustrates the difficulty of predicting carbon emissions costs, and the financial risk potentially associated with carbon emissions.

With the US decision not to ratify the Kyoto Protocol, US businesses are unable to participate in the international markets, and emissions reductions in the United States have no value in international markets. When the United States does adopt a mandatory greenhouse gas policy, the ability of US businesses and companies to participate in international carbon markets will be affected by the design of the mandatory program. For example, if the mandatory program in the United States includes a safety valve price, it may restrict participation in international markets.[72]

6.2 Values used in electric resource planning

Several companies in the electric sector evaluate the costs and risks associated with carbon emissions in resource planning. Some of them do so at their own initiative, as part of prudent business management, others do so in compliance with state law or regulation.

Some states require companies under their jurisdiction to account for costs and/or risks associated with regulation of greenhouse gas emissions in resource planning. These states include California, Oregon, Washington, Montana, Kentucky (through staff reports), and Utah. Other states, such as Vermont, require that companies take into account environmental costs generally. The Northwest Power and Conservation Council

[70] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[71] These prices are from Evolution Express trade data, http://www.evomarkets.com/, accessed on 3/31/06.

[72] See, e.g. Pershing, Jonathan, Comments in Response to Bingaman-Domenici Climate Change White Paper, March 13, 2006. Sandalow, David, Comments in Response to Bingaman-Domenici Climate Change White Paper, The Brookings Institution, March 13, 2006.

includes various carbon scenarios in its Fifth Power Plan. For more information on these requirements, see the section above on state policies.[73]

California has one of the most specific requirements for valuation of carbon in integrated resource planning. The California Public Utilities Commission (PUC) requires companies to include a carbon adder in long-term resource procurement plans. The Commission's decision requires the state's largest electric utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) to factor the financial risk associated with greenhouse gas emissions into new long-term power plant investments, and long-term resource plans. The Commission initially directed utilities to include a value between $8–25/ton CO_2 in their submissions, and to justify their selection of a number.[74] In April 2005, the Commission adopted, for use in resource planning and bid evaluation, a CO_2 adder of $8 per ton of CO_2 in 2004, escalating at 5% per year.[75] The Montana Public Service Commission specifically directed Northwest Energy to evaluate the risks associated with greenhouse gas emissions in its 2005 Integrated Resource Plan (IRP).[76] In 2006 the Oregon Public Utilities Commission (PUC) will be investigating its long-range planning requirements, and will consider whether a specific carbon adder should be required in the base case (Docket UM 1056).

Several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs in their long term planning, and have set specific agendas to mitigate shareholder risks associated with future US carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the US electric sector emissions contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[77] Table 6.1 illustrates the range of carbon cost values, in $/ton CO_2, that are currently being used in the industry for both resource planning and modeling of carbon regulation policies.

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[73] For a discussion of the use of carbon values in integrated resource planning see, Wiser, Ryan, and Bolinger, Mark; *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans;* Lawrence Berkeley National Laboratories; August 2005. LBNL-58450

[74] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

[75] California Public Utilities Commission, Decision 05-04-024, April 2005.

[76] Montana Public Service Commission, "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229," August 17, 2004.

[77] Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

Table 6.1 CO_2 Costs in Long Term Resource Plans

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

These early efforts by utilities have brought consideration of the risks associated with future carbon regulations into the mainstream in resource planning the electric sector.

6.3 Analyses of carbon emissions reduction costs

With the emergence of federal policy proposals in the United States in the past several years, there have been several policy analyses that project the cost of carbon-dioxide equivalent emission allowances under different policy designs. These studies reveal a range of cost estimates. While it is not possible to pinpoint emissions reduction costs given current uncertainties about the goal and design of carbon regulation as well as the inherent uncertainties in any forecast, the studies provide a useful source of information for inclusion in resource decisions. In addition to establishing ranges of cost estimates, the studies give a sense of which factors affect future costs of reducing carbon emissions.

There have been several studies of proposed federal cap and trade programs in the United States. Table 6.2 identifies some of the major recent studies of carbon policy proposals.

Table 6.2. Analyses of US Carbon Policy Proposals

Policy proposal	Analysis
McCain Lieberman – S. 139	EIA 2003, MIT 2003, Tellus 2003
McCain Lieberman – SA 2028	EIA 2004, MIT 2003, Tellus 2004
Greenhouse Gas Intensity Targets	EIA 2005, EIA 2006
Jeffords – S. 150	EPA 2005
Carper 4-P – S. 843	EIA 2003, EPA 2005

Both versions of the McCain and Lieberman proposal (also known as the Climate Stewardship Act) were the subject of analyses by EIA, MIT, and the Tellus Institute. As originally proposed, the McCain Lieberman legislation capped 2010 emissions at 2000 levels, with a reduction in 2016 to 1990 levels. As revised, McCain Lieberman just included the initial cap at 2000 levels without a further restriction. In its analyses, EIA ran several sensitivity cases exploring the impact of technological innovation, gas prices, allowance auction, and flexibility mechanisms (banking and international offsets). [78]

In 2003 researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation.[79] MIT held emissions for 2010 and beyond at 2000 levels (not modeling the second step of the proposed legislation). Due to constraints of the model, the MIT group studied an economy-wide emissions limit rather than a limit on the energy sector. A first set of scenarios considers the cap tightening in Phase II and banking. A second set of scenarios examines the possible effects of outside credits. And a final set examines the effects of different assumptions about baseline gross domestic product (GDP) and emissions growth.

The Tellus Institute conducted two studies for the Natural Resources Defense Council of the McCain Lieberman proposals (July 2003 and June 2004).[80] In its analysis of the first proposal (S. 139), Tellus relied on a modified version of the National Energy Modeling System that used more optimistic assumptions for energy efficiency and renewable energy technologies based on expert input from colleagues at the ACEEE, the Union of Concerned Scientists, the National Laboratories and elsewhere. Tellus then modeled two policy cases. The "Policy Case" scenario included the provisions of the Climate Stewardship Act (S.139) as well as oil savings measures, a national renewable transportation fuel standard, a national RPS, and emissions standards contained in the Clean Air Planning Act. The "Advanced Policy Case" included the same complimentary energy policies as the "Policy Case" and assumed additional oil savings in the

[78] Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, EIA June 2003, SR/OIAF/2003-02; Energy Information Administration, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, EIA May 2004, SR/OIAF/2004-06

[79] Paltsev, Sergei; Reilly, John M.; Jacoby, Henry D.; Ellerman, A. Denny; Tay, Kok Hou; *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal.* MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

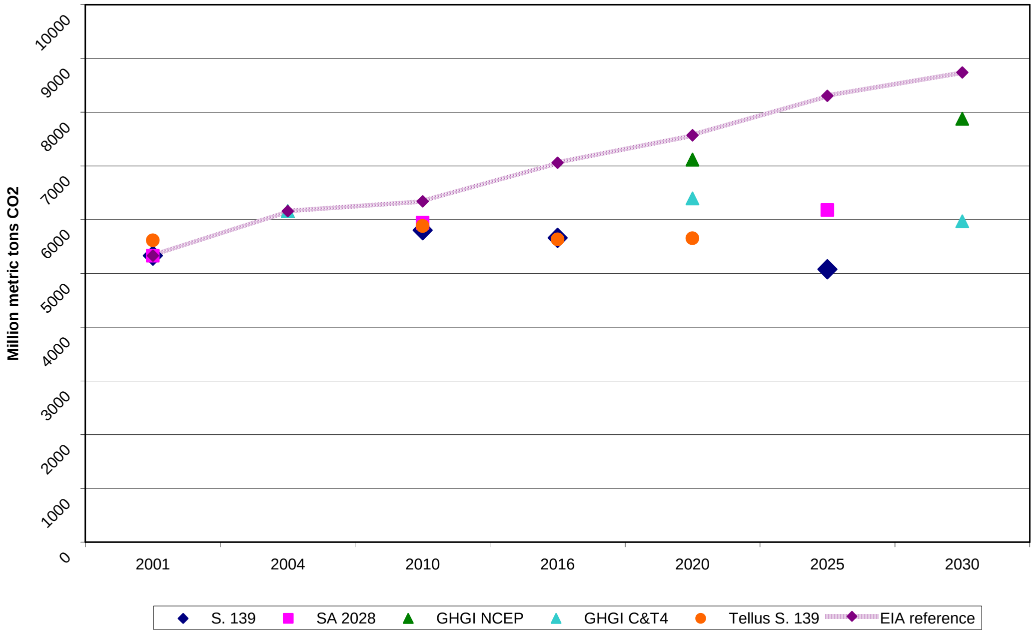
[80] Bailie et al., *Analysis of the Climate Stewardship Act*, July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ) (25 mpg in 2005, increasing to 45 mpg in 2025).

EIA has also analyzed the effect and cost of greenhouse gas intensity targets as proposed by Senator Bingaman based on the National Commission on Energy Policy, as well as more stringent intensity targets.[81] Some of the scenarios included safety valve prices, and some did not.

In addition to the analysis of economy-wide policy proposals, proposals for GHG emissions restrictions have also been analyzed. Both EIA and the U.S. Environmental Protection Agency (EPA) analyzed the four-pollutant policy proposed by Senator Carper (S. 843).[82] EPA also analyzed the power sector proposal from Senator Jeffords (S. 150).[83]

Figure 6.1 shows the emissions trajectories that the analyses of economy-wide policies projected for specific policy proposals. The graph does not include projections for policies that would just apply to the electric sector since those are not directly comparable to economy-wide emissions trajectories.



[81] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,* March 2006. SR/OIAF/2006-01.

[82] EIA. Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003. EIA Office of Integrated Analysis and Forecasting. SR/OIAF/2003-03. September 2003. US EPA, *Multi-pollutant Legislative Analysis: The Clean Power Act (Jeffords, S. 150 in the 109th).* US EPA Office of Air and Radiation, October 2005.

[83] US Environmental Protection Agency, *Multi-pollutant Legislative Analysis: The Clean Air Planning Act (Carper, S. 843 in the 108th).* US EPA Office of Air and Radiation, October 2005.

Figure 6.1. Projected Emissions Trajectories for US Economy-wide Carbon Policy Proposals.

Projected emissions trajectories from EIA and Tellus Institute Analyses of US economy-wide carbon policies. Emissions projections are for "affected sources" under proposed legislation. S. 139 is the EIA analysis of McCain Lieberman Climate Stewardship Act from 2003, SA 2028 is the EIA analysis of McCain Lieberman Climate Stewardship Act as amended in 2005. GHGI NCEP is the EIA analysis of greenhouse gas intensity targets recommended by the National Commission on Energy Policy and endorsed by Senators Bingaman and Domenici, GHGIC&T4 is the most stringent emission reduction target modeled by EIA in its 2006 analysis of greenhouse gas intensity targets, and Tellus S.139 is from the Tellus Institute analysis of S. 139.

Figure 6.2 presents projected carbon allowance costs from the economy-wide and electric sector studies in constant 2005 dollars per ton of carbon dioxide.

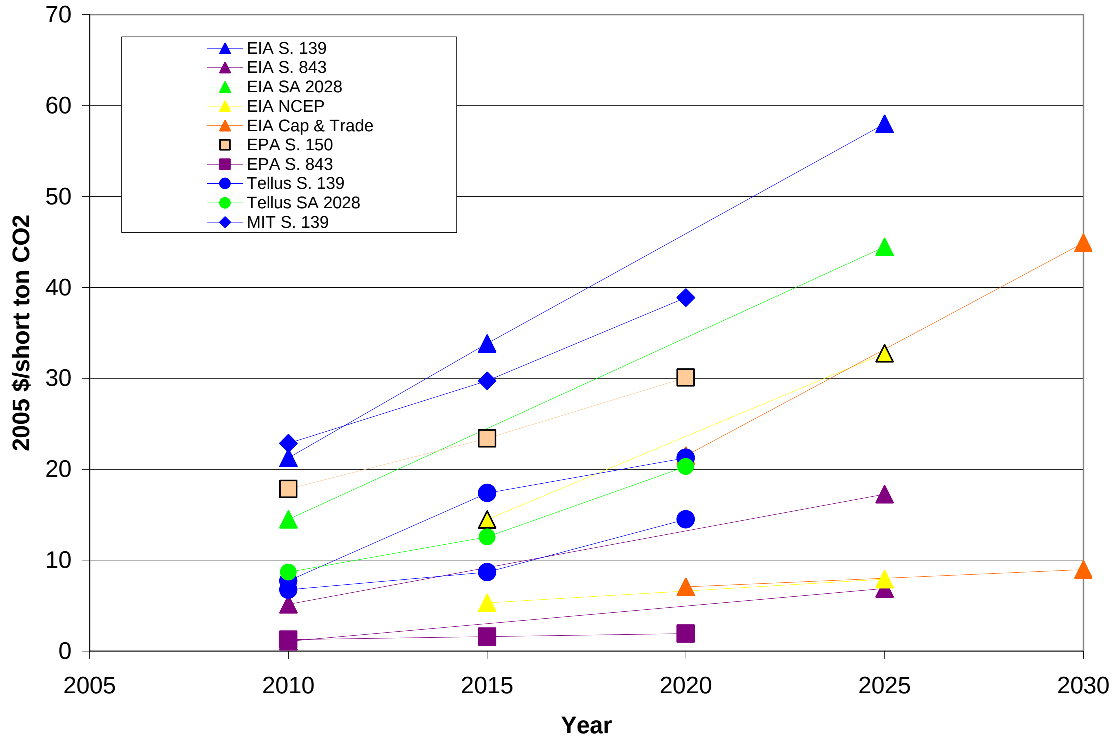


Figure 6.2. Allowance Cost Estimates From Studies of Economy-wide and Electric Sector US Policy Proposals

Carbon emissions price forecasts based on a range of proposed federal carbon regulations. Sources of data include: Triangles – US Energy Information Agency (EIA); Square – US EPA; Circles – Tellus Institute; Diamond – MIT. All values shown have been converted into 2005 dollars per short ton CO2 equivalent. Color-coded policies evaluated include:

Blue: *S. 139, the McCain-Lieberman Climate Stewardship Act of January 2003. MIT Scenario includes banking and zero-cost credits (effectively relaxing the cap by 15% and 10% in phase I and II, respectively.) The Tellus scenarios are the "Policy" case (higher values) and the "Advanced" case (lower values). Both Tellus cases include complimentary emission reduction policies, with "advance" policy case assuming additional oil savings in the transportation sector from increase the fuel efficiency of light-duty vehicles (CAFÉ).*

Tan: *S.150, the Clean Power Act of 2005*

Violet: *S. 843, the Clean Air Planning Act of 2003. Includes international trading of offsets. EIA data include "High Offsets"(lower prices) and "Mid Offsets" (higher prices) cases. EPA data shows effect of tremendous offset flexibility.*

Bright Green: *SA 2028, the McCain-Lieberman Climate Stewardship Act Amendment of October 2003. This version sets the emissions cap at constant 2000 levels and allows for 15% of the carbon reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources.*

Yellow: *EIA analysis of the National Commission on Energy Policy (NCEP) policy option recommendations. Lower series has a safety-valve maximum permit price of $6.10 per metric ton CO2 in 2010 rising to $8.50 per metric ton CO2 in 2025, in 2003 dollars. Higher series has no safety value price. Both include a range of complementary policies recommended by NCEP.*

Orange: *EIA analysis of cap and trade policies based on NCEP, but varying the carbon intensity reduction goals. Lower-priced series (Cap and trade 1) has an intensity reduction of 2.4%/yr from 2010 to 2020 and 2.8%/yr from 2020 to 2030; safety-valve prices are $6.16 in 2010, rising to $9.86 in 2030, in 2004 dollars. Higher-priced series (Cap and trade 4) has intensity reductions of 3% per year and 4% per year for 2010-2020 and 2020-2030, respectively, and safety-valve prices of $30.92 in 2010 rising to $49.47 in 2030, in 2004 dollars.*

The lowest allowance cost results (EPA S. 843, EIA NCEP, and EIA Cap & Trade) correspond to the EPA analysis of a power sector program with very extensive offset use, and to EIA analyses of greenhouse gas intensity targets with allowance safety valve prices. In these analyses, the identified emission reduction target is not achieved because the safety valve is triggered. In EIA GHGI C&T 4, the price is higher because the greenhouse gas intensity target is more stringent, and there is no safety valve. The EIA analysis of S. 843 shows higher cost projections because of the treatment of offsets, which clearly cause a huge range in the projections for this policy. In the EPA analysis, virtually all compliance is from offsets from sources outside of the power sector.

In addition to its recent modeling of US policy proposals, EIA has performed several studies projecting costs associated with compliance with the Kyoto Protocol. In 1998, EIA performed a study analyzing allowance costs associated with six scenarios ranging from emissions in 2010 at 24 percent above 1990 emissions levels, to emissions in 2010 at 7 percent below 1990 emissions levels.[84] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the

[84] EIA, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

original study.[85] Carbon dioxide costs projected in these EIA studies of Kyoto targets were generally higher than those projected in the studies of economy-wide legislative proposals due in part to the more stringent emission reduction requirements of the Kyoto Protocol. For example, carbon dioxide allowances for 2010 were projected at $91 per short ton CO_2 ($2005) and $100 per short ton CO_2 ($2005) respectively for targets of seven percent below 1990 emissions levels. While the United States has not ratified the Kyoto Protocol, these studies are informative since they evaluate more stringent emission reduction requirements than those contained in current federal policy proposals. Scientists anticipate that avoiding dangerous climate change will require even steeper reductions than those in the Kyoto Protocol.

The State Working Group of the RGGI in the Northeast engaged ICF Consulting to analyze the impacts of implementing a CO2 cap on the electric sector in the northeastern states. ICF used the IPM model to analyze the program package that the RGGI states ultimately agreed to. ICF's analysis results (in $2004) range from $1-$5/ton CO_2 in 2009 to about $2.50-$12/ton CO_2 in 2024.[86] The lowest CO2 allowance prices are associated with the RGGI program package under the expected emission growth scenario. The costs increase significantly under a high emissions scenario, and increase even more when the high emissions scenario is combined with a national cap and trade program due to the greater demand for allowances in a national program. ICF performed some analysis that included aggressive energy efficiency scenarios and found that those energy efficiency components would reduce the costs of the RGGI program significantly.

In 2003 ICF was retained by the state of Connecticut to model a carbon cap across the 10 northeastern states. The cap is set at 1990 levels in 2010, 5 percent below 1990 levels in 2015, and 10 percent below 1990 levels in 2020. The use of offsets is phased in with entities able to offset 5 percent or their emissions in 2015 and 10 percent in 2020. The CO_2 allowance price, in $US2004, for the 10-state region increases over the forecast period in the policy case, rising from $7/ton in 2010 to $11/ton in 2020.[87]

6.4 Factors that affect projections of carbon cost

Results from a range of studies highlight certain factors that affect projections of future carbon emissions prices. In particular, the studies provide insight into whether the factors increase or decrease expected costs, and to the relationships among different factors. A number of the key assumptions that affect policy cost projections (and indeed policy costs) are discussed in this section, and summarized in Table 6.3.

[85] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol," July 1999. SR/OIAF/99-02.

[86] ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

[87] Center for Clean Air Policy, *Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee*, January 2004, p. 3.3-27.

Here we only consider these factors in a qualitative sense, although quantitative meta-analyses do exist.[88] It is important to keep these factors in mind when attempting to compare and survey the range of cost/benefit studies for carbon emissions policies so the varying forecasts can be kept in the proper perspective.

Base case emissions forecast

Developing a business-as-usual case (in the absence of federal carbon emission regulations) is a complex modeling exercise in itself, requiring a wide range of assumptions and projections which are themselves subject to uncertainty. In addition to the question of future economic growth, assumptions must be made about the emissions intensity of that growth. Will growth be primarily in the service sector or in industry? Will technological improvements throughout the economy decrease the carbon emissions per unit of output?

In addition, a significant open question is the future generation mix in the United States. Throughout the 1990s most new generating investments were in natural gas-fired units, which emit much less carbon per unit of output than other fossil fuel sources. Today many utilities are looking at baseload coal due to the increased cost of natural gas, implying much higher emissions per MWh output. Some analysts predict a comeback for nuclear energy, which despite its high cost and unsolved waste disposal and safety issues has extremely low carbon emissions.

A business-as-usual case which included several decades of conventional base load coal, combined with rapid economic expansion, would present an extremely high emissions baseline. This would lead to an elevated projected cost of emissions reduction regardless of the assumed policy mechanism.

Complimentary policies

Complimentary energy policies, such as direct investments in energy efficiency, are a very effective way to reduce the demand for emissions allowances and thereby to lower their market price. A policy scenario which includes aggressive energy efficiency along with carbon emissions limits will result in lower allowances prices than one in which energy efficiency is not directly addressed.[89]

Policy implementation timeline and reduction target

Most "policy" scenarios are structured according to a goal such as achieving "1990 emissions by 2010" meaning that emissions should be decreased to a level in 2010 which

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[88] See, *e.g.*, Carolyn Fischer and Richard D. Morgenstern, *Carbon Abatement Costs: Why the Wide Range of Estimates?* Resources for the Future, September, 2003. http://www.rff.org/Documents/RFF-DP-03-42.pdf

[89] A recent analysis by ACEEE demonstrates the effect of energy efficiency investments in reducing the projected costs of the Regional Greenhouse Gas Initiative. Prindle, Shipley, and Elliott; *Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative*; American Council for an Energy Efficient Economy, May 2006. Report Number E064.

is no higher than they were in 1990. Both of these policy parameters have strong implications for policy costs, although not necessarily in the intuitive sense. A later implementation date means that there is more time for the electric generating industry to develop and install mitigation technology, but it also means that if they wait to act, they will have to make much more drastic cuts in a short period of time. Models which assume phased-in targets, forcing industry to take early action, may stimulate technological innovations so that later, more aggressive targets can be reached at lower cost.

Program flexibility

The philosophy behind cap and trade regulation is that the rules should specify an overall emissions goal, but the market should find the most efficient way of meeting that goal. For emissions with broad impacts (as opposed to local health impacts) this approach will work best at minimizing cost if maximum flexibility is built into the system. For example, trading should be allowed across as broad as possible a geographical region, so that regions with lower mitigation cost will maximize their mitigation and sell their emission allowances. This need not be restricted to CO_2 but can include other GHGs on an equivalent basis, and indeed can potentially include trading for offsets which reduce atmospheric CO_2 such as reforestation projects. Another form of flexibility is to allow utilities to put emissions allowances "in the bank" to be used at a time when they hold higher value, or to allow international trading as is done in Europe through the Kyoto protocol.

One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. [90] Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable."[91] Still, there is a clear benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume higher flexibility in all of these areas are likely to predict lower compliance costs for reaching any specified goal.

Technological progress

The rate of improvement in mitigation technology is a crucial assumption in predicting future emissions control costs. This has been an important factor in every major air emissions law, and has resulted, for example, in the pronounced downward trend in allowance prices for SO_2 and NO_x in the years since regulations of those two pollutants were enacted. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in carbon-free generation

[90] An additional consideration is that greater geographic flexibility reduces potential local co-benefits, discussed below, that can derive from efforts to reduce greenhouse gas emissions.

[91] Massachusetts 310 CMR 7.29.

technologies. Improvements in the efficiency of coal burning technology or in the cost of nuclear power plants may also be a factor.

Reduced emissions co-benefits

Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2 and mercury. This results in cost savings not only to the generators who no longer need these permits, but also to broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

Table 6.3. Factors That Affect Future Carbon Emissions Policy Costs

Assumption	Increases Prices if…	Decreases Prices if…
• **"Base case" emissions forecast**	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual" emissions
• **Complimentary policies**	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
• **Policy implementation timeline**	Delayed and/or sudden program implementation	Early action, phased-in emissions limits.
• **Reduction targets**	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
• **Program flexibility**	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects.
• **Technological progress**	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions
• **Emissions co-benefits**	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants.

Because of the uncertainties and interrelationships surrounding these factors, forecasting long-range carbon emissions price trajectories is quite complicated and involves significant uncertainty. Of course, this uncertainty is no greater than the uncertainty surrounding other key variables underlying future electricity costs, such as fuel prices, although there are certain characteristics that make carbon emissions price forecasting unique.

One of these is that the forecaster must predict the future political climate. As documented throughout this paper, recent years have seen a dramatic increase in both the documented effects of and the public awareness of global climate change. As these trends continue, it is likely that more aggressive and more expensive emissions policies will be politically feasible. Political events in other areas of the world may be another factor, in that it will be easier to justify aggressive policies in the United States if other nations such as China are also limiting emissions.

Another important consideration is the relationship between early investments and later emissions costs. It is likely that policies which produce high prices early will greatly accelerate technological innovation, which could lead to prices in the following decades which are lower than they would otherwise be. This effect has clearly played a role in NO_x and SO_2 allowance trading prices. However, the effect would be offset to some degree by the tendency for emissions limits to become more restrictive over time, especially if mitigation becomes less costly and the effects of global climate change become increasingly obvious.

6.5 Synapse forecast of carbon dioxide allowance prices

Below we offer an emissions price forecast which the authors judge to represent a reasonable range of likely future CO_2 allowance prices. Because of the factors discussed above and others, it is likely that the actual cost of emissions will not follow a smooth path like those shown here but will exhibit swings between and even outside of our “low” and “high” cases in response to political, technological, market and other factors. Nonetheless, we believe that these represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation.

Figure 6.3 shows our price forecasts for the period 2010 through 2030, superimposed upon projections collected from other studies mentioned in this paper.

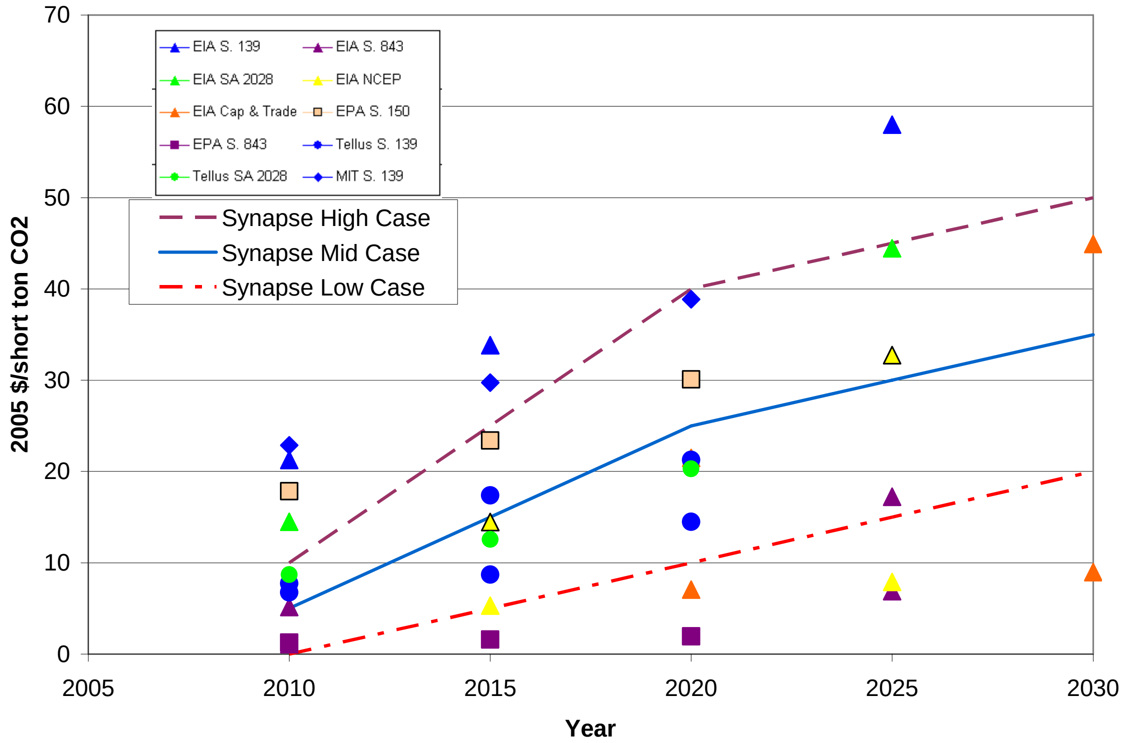

Figure 6.3. Synapse Forecast of Carbon Dioxide Allowance Prices

High, mid and low-case Synapse carbon dioxide emissions price forecasts superimposed on policy model forecasts as presented in Figure 6.2.

In developing our forecast we have reviewed the cost analyses of federal proposals, the Kyoto Protocol, and current electric company use of carbon values in IRP processes, as described earlier in this paper. The highest cost projections from studies of U.S. policy proposals generally reflect a combination of factors including more aggressive emissions reductions, conservative assumptions about complimentary energy policies, and limited or no offsets. For example, some of the highest results come from EIA analysis of the most aggressive emission reductions proposed -- the Climate Stewardship Act, as originally proposed by Senators McCain and Lieberman in 2003. Similarly, the highest cost projection for 2025 is from the EPA analysis of the Carper 4-P bill, S. 843, in a scenario with fairly restricted offset use. The lowest cost projections are from the analysis of the greenhouse gas intensity goal with a safety valve, as proposed by the National Commission on Energy Policy, as well as from an EPA analysis of the Carper 4-P bill, S. 843, with no restrictions on offset use. These highest and lowest cost estimates illustrate the effect of the factors that affect projections of CO_2 emissions costs, as discussed in the previous section.

We believe that the U.S. policies that have been modeled can reasonably be considered to represent the range of U.S. policies that could be adopted in the next several years. However, we do not anticipate the adoption of either the most aggressive or restrictive, or the most lenient and flexible policies illustrated in the range of projections from recent analyses. Thus we consider both the highest and the lowest cost projections from those studies to be outside of our reasonable forecast.

We note that EIA projections of costs to comply with Kyoto Protocol targets were much higher, in the range of $100/ton CO_2. The higher cost projections associated with the Kyoto Protocol targets, which are somewhat more aggressive than U.S. policy proposals, are consistent with the anticipated effect of a more carbon-constrained future. The EIA analysis also has pessimistic assumptions regarding carbon emission-reducing technologies and complementary policies. The range of values that certain electric companies currently use in their resource planning and evaluation processes largely fall within the high and low cost projections from policy studies. Our forecast of carbon dioxide allowance prices is presented in Table 6.4.

Table 6.4. Synapse forecast of carbon dioxide allowance prices ($2005/ton CO_2).

	2010	**2020**	**2030**	**Levelized Value 2011-2030**
Synapse Low Case	0	10	20	8.23
Synapse Mid Case	5	25	35	19.83
Synapse High Case	10	40	50	31.43

As illustrated in the table, we have identified what we believe to be a reasonable high, low, and mid case for three time periods: 2010, 2020, and 2030. These high, low, and mid case values for the years in question represent a range of values that are reasonably plausible for use in resource planning. Certainly other price trajectories are possible, indeed likely depending on factors such as level of reduction target, and year of implementation of a policy. We have much greater confidence in the levelized values over the period than we do in any particular annual values or in the specific shape of the price projections.

Using these value ranges, we have plotted cost lines in Figure 6.3 for use in resource analysis. In selecting these values, we have taken into account a variety of factors for the three time periods. While some regions and states may impose carbon emissions costs sooner, or federal legislation may be adopted sooner, our assumption conservatively assumes that implementation of any federal legislative requirements is unlikely before 2010. We project a cost in 2010 of between zero and $10 per ton of CO_2.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices reflects the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). Thus we find the widest uncertainty in our forecasts begins at the end of this decade from $10 to $40 per ton of CO_2, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward the marginal mitigation cost of carbon emissions. This number still depends on uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that the least expensive mitigation options (such as simple energy efficiency and fuel switching) will be exhausted. Our projection for the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

We think the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, making the most likely scenario closer to (though not equal to) low case scenarios than the high case scenario. The probability of taking this path increases over time, as society learns more about optimal carbon reduction policies.

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices increases due to interplay of factors such as the level of carbon constraints required, and technological innovation. As discussed in previous sections, scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though the cost of such deeper cuts has not been quantified on a per ton basis.

On the other hand, we also anticipate a reasonable likelihood that increasing concern over climate change impacts, and the accompanying push for more aggressive emission reductions, will drive technological innovation, which may be anticipated to prevent unlimited cost escalation. For example, with continued technology improvement, coupled with attainment of economies of scale, significant price declines in distributed generation, grid management, and storage technologies, are likely to occur. The combination of such price declines and carbon prices could enable tapping very large supplies of distributed resources, such as solar, low-speed wind and bioenergy resources, as well as the development of new energy efficiency options. The potential development of carbon sequestration strategies, and/or the transition to a renewable energy-based economy may also mitigate continued carbon price escalation.

7. Conclusion

The earth's climate is strongly influenced by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in the Third Assessment Report of the Intergovernmental Panel on Climate Change and in countless peer-reviewed scientific studies and reports, is that the climate system is already being – and will continue to be – disrupted due to anthropogenic emissions of greenhouse gases. Scientists expect increasing atmospheric concentrations of greenhouse gases to cause temperature increases of 1.4 – 5.8 degrees centigrade by 2100, the fastest rate of change since end of the last ice age. Such global warming is expected to cause a wide range of climate impacts including changes in precipitation patterns, increased climate variability, melting of glaciers, ice shelves and permafrost, and rising sea levels. Some of these changes have already been observed and documented in a growing body of scientific literature. All countries will experience social and economic consequences, with disproportionate negative impacts on those countries least able to adapt.

The prospect of global warming and changing climate has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions by industrialized nations and by economies in transition.

The United States, which is the single largest contributor to global emissions of greenhouse gases, remains one of a very few industrialized nations that have not signed onto the Kyoto Protocol. Nevertheless, federal legislation seems likely in the next few years, and individual states, regional organizations, corporate shareholders and corporations themselves are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon emissions, though not yet successful, have gained ground in recent years. And climate change issues have seen an unprecedented level of attention in the United States at all levels of government in the past few years.

These developments, combined with the growing scientific certainty related to climate change, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how, and how much additional damage will have been incurred by the process of delay. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of controlling emissions from large point sources. While the future costs of compliance are subject to uncertainty, they are real and will be mandatory within the lifetime of electric industry capital stock being planned for and built today.

In this scientific, policy and economic context, it is imprudent for decision-makers in the electric sector to ignore the cost of future carbon emissions reductions or to treat future carbon emissions reductions merely as a sensitivity case. Failure to consider the potential future costs of greenhouse gas emissions under future mandatory emission reductions will result in investments that prove quite uneconomic in the future. Long term resource planning by utility and non-utility owners of electric generation must account for the cost of mitigating greenhouse gas emissions, particularly carbon dioxide. For example, decisions about a company's resource portfolio, including building new power plants, reducing other pollutants or installing pollution controls, avoided costs for efficiency or renewables, and retirement of existing power plants all can be more sophisticated and more efficient with appropriate consideration of future costs of carbon emissions mitigation.

Regulatory uncertainty associated with climate change clearly presents a planning challenge, but this does not justify proceeding as if no costs will be associated with carbon emissions in the future. The challenge, as with any unknown future cost driver, is to forecast a reasonable range of costs based on analysis of the information available. This report identifies many sources of information that can form the basis of reasonable assumptions about the likely costs of meeting future carbon emissions reduction requirements.

Additional Costs Associated with Greenhouse Gases

It is important to note that the greenhouse gas emission reduction requirements contained in federal legislation proposed to date, and even the targets in the Kyoto Protocol, are relatively modest compared with the range of emissions reductions that are anticipated to be necessary for keeping global warming at a manageable level. Further, we do not attempt to calculate the full cost to society (or to electric utilities) associated with anticipated future climate changes. Even if electric utilities comply with some of the most aggressive regulatory requirements underlying our CO_2 price forecasts presented above, climate change will continue to occur, albeit at a slower pace, and more stringent emissions reductions will be necessary to avoid dangerous changes to the climate system.

The consensus from the international scientific community clearly indicates that in order to stabilize the concentration of greenhouse gases in the atmosphere and to try to keep further global warming trends manageable, greenhouse gas emissions will have to be reduced significantly below those limits underlying our CO_2 price forecasts. The scientific consensus expressed in the Intergovernmental Panel on Climate Change Report from 2001 is that greenhouse gas emissions would have to decline to a very small fraction of current emissions in order to stabilize greenhouse gas concentrations, and keep global warming in the vicinity of a 2-3 degree centigrade temperature increase. Simply complying with the regulations underlying our CO_2 price forecasts does not eliminate the ecological and socio-economic threat created by CO_2 emissions – it merely mitigates that threat.

Incorporating a reasonable CO_2 price forecast into electricity resource planning will help address electricity consumer concerns about prudent economic decision-making and direct impacts on future electricity rates. However, current policy proposals are just a first step in the direction of emissions reductions that are likely to ultimately be necessary. Consequently, electric sector participants should anticipate increasingly stringent regulatory requirements. In addition, anticipating the financial risks associated with greenhouse gas regulation does not address all the ecological and socio-economic concerns posed by greenhouse gas emissions. Regulators should consider other policy mechanisms to account for the remaining pervasive impacts associated with greenhouse gas emissions.

This report is unchanged from the August 31, 2006 version except for the correction of a graphical error.

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