ORIGINAL

WildLaw

A Non-profit Environmental Law Firm

November 2, 2006

BY HAND DELIVERY

RECEIVED-FPSC
06 NOV -2 PM 4:51
COMMISSION CLERK

Ms. Blanca S. Bayo, Director
Division of Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 060635-EU

Dear Ms. Bayo,

Enclosed for filing in the above-referenced docket are fifteen (15) copies of the testimony of Dian Deevey on behalf of Intervenors Dianne V. Whitfield, Carole E. Taitt and John Carl Whitton, Jr. Copies of this testimony have been provided via U.S. Mail to the parties.

Please acknowledge the filing of this testimony by date stamping the enclosed copy of this letter and returning it to the individual who has hand delivered it.

Thank you for your assistance.

Sincerely,

Brett M. Paben
Staff Attorney

CMP ____
COM 5
CTR Org
ECR ____
GCL 1
OPC ____
RCA ____
SCR ____
SGA ____
SEC 1
OTH ____

Florida Office
1415 Devils Dip • Tallahassee, Florida 32308 • p: 850.878.6895 • f: 850-878-6895 • www.wildlaw.org

DOCUMENT NUMBER-DATE
10166 NOV-2 06
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY DIAN DEEVY

ON BEHALF OF

DIANNE V. WHITFIELD, CAROLE E. TAITT, JOHN CARL WHITTON, JR.

DOCKET NO. 060635

NOVEMBER 2, 2006

Q. Please state your name and business address.

A. My name is Dian Deevey and my address is 1702 SW 35th Place, Gainesville FL, 32608.

Q. Please briefly describe your educational background and work experience.

A. I received a bachelors' degree magna cum laude from Stanford University, in Philosophy. My early professional career was devoted chiefly to the design of computer systems (hardware and software), and artificial intelligence. In 1964 as an employee of United Technologies I received NASA funding to survey and review experimental approaches to the detection of life on Mars. From then until 1985 I conducted basic research in the biogeochemistry of the atmosphere, supported by NASA, as an employee of United Technologies and subsequently as an independent consultant. It featured the design and interpretation of field experiments on the biogenic sulfur cycle and on the chemistry of sea salt particles.. My research has focused chiefly on the natural sulfur cycle and sea salt particles. I received funding from NASA, NSF, and EPA, and designed, conducted, and interpreted field experiments. I retired from active research in 1985.

Q. Do you have experience in electric utility resource planning?

A. Yes. I have conducted detailed studies of the needs of my local municipal utility Gainesville Regional Utilities (GRU) for new capacity and ways to satisfy those needs for over three years.

Q. Why did you initiate these investigations?

A. Biogeochemistry of the atmosphere is a highly interdisciplinary field that integrates many subjects that are critically relevant to contemporary climate science, and fundamental to studies of the causes and consequences of global warming. I have followed scientific developments in global warming for many years. In 2003 when they planned a new coal-based generator, GRU management were oblivious to global warming issues, and believed that emissions of carbon dioxide were unrelated to global warming. I am and was a member of the Alachua County Environmental Protection Advisory Committee (EPAC), and at my urging and other EPAC members, the County Commission formally requested EPAC to conduct a review of GRU's plans and their environmental impact.

Q. How was the review conducted and what was its outcome?

A. I conducted the review, with the help of Dr. David Harlos, a Gainesville resident with extensive experience in the health effects of air pollution. Together we produced a long written assessment of GRU's plans. This review was based on a careful study of GRU's plans and the reports of its consultants, together with extensive study of the voluminous literature of energy economics, integrated resource planning, demand side management, regulatory policy, legislative initiatives for the reduction greenhouse gas emissions both here and in other countries, and other important subjects. After about 18 months of intensive work, Dr., Harlos and I produced a written report of our findings[1], and at my request, the Alachua County Commission allocated money to pay for a professional peer review of the document.

Q. What did the reviewers report about your study?

A. The reviewers praised its professionalism, its balance, and its objectivity. All agreed with the findings, with a single minor exception. I was very gratified by the review.

Q. What in your opinion were the most important conclusions of your study?

A. We concluded that large investments in coal-based generators are too risky for municipal utilities in the present energy environment, given the extreme regulatory and technological uncertainties. Regulatory uncertainties derive from global warming and the need to reduce

---

[1] "Review of the Gainesville Regional Utilities' Proposal for a New Coal-Fired Power Plant" Prepared by Dian Deevey and David Harlos Sc.D. For The Alachua County Environmental Protection Advisory Committee Submitted to the Alachua County Board of County Commissioners. September 15, 2005, attached as Exhibit DD1.

carbon dioxide emissions very substantially in a short time, which will result in regulations that either impose financial sanctions on greenhouse gas emissions by utilities and/or offer subsidies that make other energy sources far more attractive to consumers. In both cases, the result could be financial problems for the utilities, their customers, and their municipal owners. There is a huge market for technological innovations in energy technologies that entail greatly reduced greenhouse gas emissions. Many established and new companies are working on radically new and possibly even revolutionary technologies to serve these growing markets. One promising possibility was announced in June by a Silicon Valley company called Nanosolar, which is one of several organizations working on novel solar PV technologies. They use a new nano-technology based solar PV system that is much easier and cheaper to produce than the conventional silicon-based system. Production is so cheap that it is expected to cut the cost of solar PV by a factor of four or five, making it cost-competitive with conventional electric energy over much of the world, and make distributed solar energy a reality in Florida and elsewhere.

Given these uncertainties, the prudent course for Gainesville and other municipalities is to make heavy demand side investments, and where possible adopt alternative energy sources.

Q. What is the purpose of your testimony today?

A. I have reviewed the application for a certificate of need by Jacksonville Electric Authority, ("JEA"), the City of Tallahassee, Reedy Creek Improvement District ("RCID"), and the Florida Municipal Power Agency ("FMPA") (hereinafter "Applicants"), for a 765 MW pulverized coal plant to be known as the Taylor Energy Center ("TEC"). I have two major criticisms of the Applicant's claim that a supercritical pulverized coal plant is the most cost-effective way to satisfy projected increases in the demand for electricity by the customers of the Applicants:

1. Applicants have not adequately assessed less costly means of meeting their projected demand. Testimony of other intervenors will demonstrate that Applicants have not adequately assessed the prospects of energy efficiency, conservation and demand-side management initiatives. It is my opinion specifically, that Applicants have not adequately evaluated generation of electricity using woody biomass, an alternative fuel with many environmental and cost advantages, or compared them to the other fossil fuel-based generators they have considered. Based on what I can ascertain from the Applicants' filings, their consultants appear wrongly to have assumed that woody biomass supplies are too limited in the locations of interest to support more than about 50 MW of capacity in any suitable location.

2. The participants base their estimates of the compliance costs of future greenhouse gas emission reduction regulations on (a) the 2005 version of the McCain-Lieberman Climate Stewardship Act, legislation which would be incapable of effective reductions in greenhouse gas emissions were it to be passed by the Congress, and (b) they also make a number of very questionable assumptions about how this act would be administered, the construction of nuclear power plants, reductions in the demand for electricity in other states than Florida, and the effectiveness of other sectors of the economy in reducing greenhouse emissions. The result is a set of estimates of allowance costs that is extremely low.

Q. What are your conclusions on the assessment by Applicants of alternative supply options to offset the pulverized plant, and specifically on the availability of biomass.

A. My knowledge of the participant's consideration of biomass-based generation is derived from reading Section A.6 of Volume A of their submission, and the testimony of Mr. Palatka, who supervised the preparation of Sections A.6.1 through A.6.4, where biomass and other alternative energy sources are discussed. Black & Veatch provided this material.

Black & Veatch did not explicitly rule out direct-fired wood-based generation, but they repeat the idea that fuel availability problems would limit size to a practical maximum of 50 MW, which is the case in many parts of the country, but not in the Southeast and, more importantly, not in Florida[2]. In any case, none of the TEC comparative studies seem to have included any conventional direct-fired biomass based generators.

Approximately half the land area of Florida is occupied by forests, and forest products are a very significant economic resource in the state. The income from forestry-based industries is Waste wood suitable for firing generators is very abundant in North and Central Florida. All the conventional forestry based industries in these areas produce waste wood, most of which is highly suitable for firing conventional spreader stoker generators, or feedstock for gasification. Florida's natural advantages for the production of biomass are illustrated by the difference between the goals of an NREL sponsored project to increase the tonnage of useable biomass from cropped land. The NREL target is 6 and 8 tons of biomass per acre per, while forests in Florida counties produce between 16 and 19 tons per year.

I have been working with a team of scientists in the School of Forestry and Conservation at the University of Florida who have conducted a detailed study of the potential for woody biomass based electricity generation in selected counties in the South East[3]. They found that most counties north of Orlando have very significant sources of woody biomass in the form of urban wood waste, forestry and mill residues and stumps. In addition, in most of them pine plantations provide pulp wood that could be purchased. Using these data, I have calculated that the Tallahassee municipal utility could fire a 100 MW generator at a fuel cost of 2 cents per kWh, assuming they purchased 60% of the urban waste wood and 70% of the forestry

---

[3] Hodges, Alan, and M. Rahmani, 2006 UF/IFAS Extension Fact Sheet, attached as Exhibit DD2.
Economic Impacts of Biomass-Fueled Electric Power Generating Plants in Selected Counties of the Southern United States. University of Florida/IFAS, Gainesville, Florida, Attached as Exhibit DD3. woody biomass fuel available to Tallahassee, Attached as DD4.

residues and stumps available within travel time of about 1 hour. Haul distances and costs are based on detailed analysis of existing road networks, and are quite realistic.

Costs are slightly higher in Alachua County, but lower in Santa Rosa and Nassau Counties. We can expect comparable costs for a new power plant of 100 to 150 MW in Duval County (JEA).

Wood based generation is carbon neutral, and some cost advantages relative to fossil fuels can be expected to continue into the indefinite future, though owners of forests can be expect to raise their prices in parallel with the costs of emission allowances, once emission reduction legislation is passed and implemented. Utilities willing to go into debt to provide power to their municipal owners might well consider purchasing forest land to secure cheap sources of biomass from which to generate electricity in the future.

Q. Is there any other subject on which you wish to offer testimony?

A. Yes. I am concerned about the participant's use of extremely low carbon dioxide emission allowance prices, and the very questionable assumptions their consultants, Hill and Associates, used to arrive at these prices.

Applicants' forecasts of compliance costs per ton of CO2 emitted range from $4.22 in 2012, to a maximum of $10.28 in 2016, after which they drop rapidly to $2.43 in 2018, and rise very slowly through the interval 2017 to 2030 to a maximum of $9.52. While these are not the lowest cost estimates I have found in the literature, their erratic progression over time from low to high and then down again is unusual. The strange behavior of these prices appears to be the consequence of some very questionable assumptions made by Hill and Associates, who produced the estimates for the Participants. Here are some problems I have noted:

Hill and Associates based their estimates on the McCain-Lieberman Climate Stewardship Act of 2005, which provides for reducing the emissions of the all covered entities in the United States to the levels emitted by the US in 2000. (These entities account for an estimated 85% US annual greenhouse gas emissions.) Compared to other legislative initiatives, this bill is extremely industry-friendly and in its present from will achieve very few reductions in total US emissions.

The bill as written provides that reductions begin in 2010, and Hill and Associates begin their analysis by determining the probable emission levels as of 2010 from Electricity Generating Units ("EGUs") as equal to 110% of EPA's estimate of emissions from this in the year 2000.) They then make the following assumptions:

1. Demand increases for some EGU's will not exceed 1% per year. No list of these EGU's is supplied, nor is the basis for selecting them fully described in the materials I have examined. This is what the relevant section of Volume A says about the method of selecting EGU's assumed to exhibit reduced demand growth: "A reduction in electricity demand growth. In the regulated-CO2 fuel and corresponding emission allowance price sensitivity scenario, electricity demand growth was limited to 1.0 percent in any area of the country that had exceeded 1.0 percent in the base case fuel price forecast."

I could find no estimate of the proportion of energy production accounted for by these EGUs, or their greenhouse gas emissions. The basic idea that some utilities will experience reduced demand growth, while the Applicants and other Florida utilities experience very significant demand growth seems illogical and should be substantiated. At the very least, one needs detailed data to determine how this assumption affects the outcome of the allocation price analysis.

2. Electric utilities in states which do not currently have any renewable energy standards are projected to aggressively shift to carbon-free energy sources. The Applicants project that electric utilities in states which do not currently have any renewable energy standards will produce an average of 12% of their energy from carbon-free ("non-emitting") sources within two years (2009), and increase their percentage of carbon-free energy production by 0.5% per year thereafter until they have achieved a total of 20% renewable energy sources. It is not clear how this is to be achieved, or whether the Applicants themselves plan to assume the burden of this conversion, as all are electric generating utilities in states that presently have no renewable energy portfolio standards.

3. Hill and Associates assume that 12 nuclear plants will come on line between 2016 and 2020, and that these will be considered non-emitters. Analysts increasingly challenge the notion that nuclear power is carbon-free, on the grounds that building and fueling them entails very significant carbon dioxide emissions equal to about one third of the greenhouse gas released by natural gas-fueled combined cycle generators with an equivalent capacity release. (Other life cycle considerations suggest that nuclear generation is not the solution to greenhouse gas reduction needs that many have assumed it to be.)

4. Aggressive reductions by non-electric generating industries. Hill and Associates also assume that other US industries covered by S 1105 will achieve more than their proportionate share of greenhouse gas reductions, which reduce the cost of tradable emission credits, and will relieve the need of EGU's to make genuine CO2 emission reductions, or even to purchase expensive allocations. The Applicants fail to provide any reasonable analysis which supports this conclusion. As recognized by the Union of Concerned Scientists in their report "Gambling on Coal: How Future Climate Laws Will Make New Coal Plants More Expensive," each new coal plant represents an enormous long-term increase in green house gases. UCS documents in its report that one 500 MW coal electric plant represents the green house gas equivalent of 600,000 cars each year. More than 150 new coal plants, most of which are of much greater capacity than 500

MW, are tentatively planned for development in the US. Unlike cars, coal plants will operate 40 to 50 years. There is virtual certainty that the any meaningful regulation of carbon and other green house gases will focus primarily on coal-fired electric plants because they are and will continue to be the largest source.

5. Further economic relief for EGU industry. The final very questionable assumption is that political pressure on the federal government will force it to give the EGU's relief in the form of special offset credits in order to buffer electricity customers from higher electricity costs. Given the recent accounts of hyper-earnings for energy companies, combined with the incredible economic burdens higher energy prices have placed on household incomes, it seems impractical that it will be politically acceptable to provide consumer relief from these higher prices by offering further supports to the energy companies.

Given the reliance on a notoriously industry-friendly legislation, the large number of additional questionable assumptions made by Hill and Associates, and the lack of data on the impact of each of these curious assumptions, I find it impossible to have any confidence in the forecast of costs of compliance with future greenhouse gas emission reduction legislation.

Q. Do you favor other estimates of compliance costs?

A. Yes. I am familiar with the several publications by consultants at the firm Synapse Energy Economics, and regard them as among the best available. Their report "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning is attached to this testimony (Ex. DD5). This firm is responsible for an evaluation of compliance costs for one of the Applicants—the City of Tallahassee Electricity Department—and I think their estimates should have been used by all the participants. At the very least, the Participants should have performed and compared the impact of compliance prices provided by Synapse with those provided by Hill and Associates. A conservative analysis of the most reasonable allowance costs demonstrate that they will increase the costs to operate coal electric plants, perhaps by as much as one-half. That's 40 to 50 years of grossly misstated operating costs if the most reasonable allowance estimates are not used.

There is one respect in which I would supplement the analysis from consultants at Synapse. I think that reviews of greenhouse gas-limiting legislative initiatives should consider the goals of the legislation—the specific tonnage of emission reductions—and determine through economic modeling whether those goals are met. Several studies of legislative proposals by the EIA have taken this approach, and found that without much higher economic sanctions than are found in many of the studies cited by Synapse, little or no actual reduction in emissions occurs. This is especially true of legislation that features low trigger prices for tradable emission rights that result in temporary lifting of the relevant caps until auction prices decline. These are typically favored by industry, but they do not achieve the stated goals of the legislation.

If legislation is to achieve the large greenhouse gas emission reductions that scientists tell us are urgently needed, the costs of allocations must be approximately the same as the costs of technology that achieves the reduction. At present, many analysts see carbon capture and sequestration as the best hope of avoiding disastrous climate effects while still provided reliable and economic electric energy to the world, Ex. DD6, attached.

The cost of removing carbon dioxide from the flue gas of a coal or natural gas fired generator should be considered in every integrated resource plan that considers these technologies. Useful estimates of the comparative costs of carbon capture and sequestration for pulverized coal generators, IGCCs and NGCCs combined cycle units has been published by Rubin, Bau and Chen, of the Carnegie Mellon University, who present representative costs in the range of \$26 to \$47 dollars per ton of CO_2 emissions avoided. These costs include capture and compression of the CO_2, but not transport to a storage site.

In my opinion, use of the most industry friendly greenhouse gas legislation introduced into the Congress as a basis for estimating the future cost of compliance grossly misrepresents the potential costs both to utility customers and to the municipalities that own the utilities. It is now a well accepted principle among knowledgeable scientists that avoidance of the most serious effects of global warming requires drastic reductions in green house gases, perhaps as much as 80 percent. This makes the adoption of federal policies as proposed by Applicants, entailing significantly more modest reductions, seem unlikely. Both the US Senate and the US House of Representatives have adopted resolutions acknowledging the scientific threat of global warming, and expressing intent to address this threat in such a way as to protect the economy and public safety.[4] Reliance on cost projections which assume significantly less stringent reductions will be government policy is imprudent of these Applicants. A conscientious study should include the most recent legislative initiatives, specifically the Safe Climate Act introduced in the US Senate last June by Senator Jeffords (S. 3698) and the companion bill introduced by Representative Waxman in the US House (HR 5642).

Q. Why is it important to address these issues in the certificate of need proceedings?

A. If the pulverized coal plant is approved without requirements for management of emissions that reflect the imminent regulatory environment, the effect of the new regulations will be completely shifted to consumers as the Applicants pass their compliance costs through. Perhaps a greater concern relates to carbon emissions. If this plant is approved and future regulations greatly reduce allowable carbon emissions, there is no commercial or economical method for post-combustion removal of carbon dioxide from a supercritical,

[4] Sense of the Senate on Climate Change, H.R. 6 §1612, Energy Policy Act of 2005 (Approved 54-43),

pulverized coal plant as proposed by Applicants. Thus, new regulations on carbon emissions will have a particularly dramatic economic effect on consumers' pocketbooks. There is tremendous potential for biomass to cost effectively meet the capacity needs of the Applicants. By acquiring additional biomass, following the City of Tallahassee's lead, the capacity needed by the Applicants will be reduced and the power available to the Applicants from biomass will be available in a shorter period of time. Based on my review of what the Applicants submitted in this proceeding, the Commission should know that nobody can reasonably evaluate whether the proposed TEC coal plant is needed or whether it is the most cost-effective source of energy without a serious analysis of the potential for biomass to cost-effectively meet the capacity needs of the Applicants. Tallahassee's independent evaluation of the biomass alternative, and the resulting contract between the City of Tallahassee and a biomass provider, should be sufficient cause for the Commission to reject the Applicants petition until a serious evaluation of the biomass alternative is performed by independent experts.

Q: Are you sponsoring exhibits?

A: Yes. The exhibits referenced in my testimony are attached to the testimony and incorporated herein.

Q. Does this conclude your testimony?

A. Yes. Given the insufficient time to prepare additional analysis and testimony, or to perform discovery to identify additional flaws in the Applicants' petition, this is all that I am able to present to the Commission at this time.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the Direct Testimony of Dian Deevey on Behalf of Dianne V. Whitfield, Carole E. Taitt, and John C. Whitton, Jr. and Exhibits have been furnished via U.S. mail to:

Gary V. Perko
Carolyn S. Raepple
Hopping Law Firm
P.O. Box 6526
Tallahassee, FL 32314
GPerko@hgslaw.com
CRaepple@ggslaw.com

Brian P. Armstrong, Esq.
7025 Lake Basin Road
Tallahassee, FL 32312
barmstrong@ngn-tally.com

E. Leon Jacobs, Jr.
Williams Law Firm
P.O. Box 1101
Tallahassee, FL 32302-1101
ljacobs50@comcast.net

Harold A. McLean
Office of the Public Counsel
111 West Madison Street, Room 812
Tallahassee, Florida 32399
hallmc@earthlink.net

on this 2nd day of November, 2006.

s/ Brett M. Paben
Brett M. Paben
Florida Bar No. 0416045
WildLaw
1415 Devils Dip
Tallahassee, FL 32308-5140
Telephone: 850-878-6895
E-mail: brett@wildlaw.org

Review of the

Gainesville Regional Utilities' Proposal for a New Coal-Fired Power Plant

Prepared by
Dian Deevey and David Harlos Sc.D.
For The
Alachua County Environmental Protection Advisory Committee

Submitted to
Alachua County Board of County Commissioners

September 15, 2005

Acknowledgments

The Alachua County Environmental Advisory Committee (EPAC) is indebted to a number of individuals who contributed in major ways to the preparation of this report. High on this list are the many members of the staff of Gainesville Regional Utilities who patiently answered endless requests for information with unfailing grace and good humor, devoting much time to teaching us about utilities and how they operate. We especially thank Mark Spiller, Jill Womble, Yolanta Jonynas, Heidi Lannon, Roger Westphal, Jennifer Hunt, Rita Strother, Ruth Martin, Dave Richardson, Ed Regan, Erica Martin, and David Barclay, and, of course, Mike Kurtz who authorized his busy staff to take the time to work with us.

Dr. John Mousa and Kathy Fanning, of the Alachua County Environmental Protection Department offered guidance and expertise on a number of subjects. Kathy sacrificed many evenings to long meetings of the EPAC Air Quality Subcommittee.

EPAC especially thanks Ms. Dian Deevey and Dr. David Harlos who researched and wrote this report. EPAC also thanks Dr. Joshua Dickinson who wrote two of the appendices to Chapter 8. The committee is indebted to many members of the local University community for information, advice and research materials. Thanks go out to the current and past members of EPAC who spent hours in numerous special meetings to help finalize this document. EPAC also greatly appreciates the work performed by Judi Scarborough to create this finished document.

Alachua County Environmental Protection Advisory Committee

Robert Brinkman
Joshua Dickinson
Sue Dudley
Kim Van Vliet
Jason Hall
Dian Deevey
Joseph Prager
Joan Douglas
Joy Ryan
Joseli Macedo
Vinay Raj
Bryan Harman

TABLE OF CONTENTS

Chapter One: Report Overview

1.0 Introduction

This is a review of Gainesville Regional Utilities' (GRU) plan to build a new coal-fired power plant and retrofit the existing coal-fired generator, Deerhaven Unit 2. The Alachua County Environmental Protection Advisory Committee (EPAC) initiated the review in February 2004[1].

In 2003, GRU requested permission from the Gainesville City Commission to proceed with one of four alternatives to meet increasing community demand for electric energy. Three of these alternatives involved building a very large new generator burning solid fuel (coal and petroleum coke) at GRU's Deerhaven site, which is already the county's largest fixed source of air pollution. Many EPAC and community members expressed concern about potential adverse impacts of added coal-fired generating capacity. The Alachua County Commission authorized a review of the GRU proposal by EPAC in January 2004. Committee members volunteered their time and expertise to conduct this extensive review. Staff of the County Environmental Protection Department assisted the volunteers.

1.1 The GRU Proposal

GRU's current proposal has been elaborated since before EPAC's review began in January 2004, but it remains remarkably similar to the original 2003 proposal with the following basic features.[2]

1. Construct a new circulating fluidized bed (CFB) generator with a net capacity of 220 Megawatts (MW) that can be fired with woodchips or other biomass fuels, but is to be primarily fueled with petroleum coke and high sulfur coal. The capital cost of this system is estimated at $550 million dollars[3], plus interest, with a 2011 startup date (provided design and site approval application were begun by the fall of 2004 or earlier).

2. Retain the existing Deerhaven Unit #2 (a 220-MW coal-fired unit) but retrofit it with emission control equipment to reduce sulfur dioxide, oxides of nitrogen, and particulate matter emissions[4]. The capital cost of this retrofit is currently estimated as $90 million.

3. Use biomass as fuel for about 30 MW of capacity in the CFB unit, if the final design permits.

4. Combine the new generator construction and the existing unit's retrofit into a single project for the purposes of site certification and permitting. One goal is to eliminate the review of the new plant's compliance with some pollution

---

[1] A brief description the steps leading up to this review, which was completed at the request of the Alachua County Commission, is contained in the Appendix to this Chapter.

[2] Source: the December 2003 report cited above, and "Staff Response to Long Term Electrical Supply Plan Questions, Issues, And Recommendations Made In November 2004 To the Gainesville City Commission" Prepared by Gainesville Regional Utilities, December 2004.

[3] This is total project cost, including the cost of retrofitting Deerhaven Unit #2, but does not include interest on money borrowed to fund the project.

[4] The details of the retrofit are obscure, especially those relating particulate emissions.

regulations normally applied to new pollution sources, including review of $PM_{2.5}$ impacts[5]. This step could reduce the retrofit costs by approximately $14 million.

5. Implement new conservation and demand response programs.

6. Establish a Greenhouse Gas Offset Fund that will expend $7.2 million dollars between 2005 and 2011 to acquire carbon offsets to compensate for carbon dioxide emissions from the new circulating fluidized bed generator, and make its operations "carbon neutral" with respect to the carbon dioxide emissions of a modern natural-gas fired combined cycle generator. GRU expects that these offsets will eliminate greenhouse gas financial penalties from future regulations through the year 2023.

7. Establish monitoring of $PM_{2.5}$ ambient concentrations (details unspecified) in the local area.

1.2 Subjects Covered by EPAC

EPAC's review first considered air pollutants derived from burning coal and petroleum coke, namely:

- Carbon dioxide emissions to the atmosphere, which contribute to global warming,
- Pollutant emissions that give rise to fine particulate matter, which has very serious adverse effects on human health.

Coal was soon revealed as a poor choice because of emissions of carbon dioxide, heavy metals and other pollutants. But unless there are reasonable alternatives to a new solid fuel plant, it is pointless to object on these grounds alone. Therefore the scope of the review expanded to include additional, closely related questions:

- Could we reduce electricity demand in our service area with more aggressive conservation and energy efficiency programs? If so, what are the barriers to implementing such programs?
- Could GRU use more biomass or other renewable energy sources to reduce pollution and reduce greenhouse gas emissions substantially?
- Has GRU fully explored the health effects of added air pollution its plan entails?
- Could mandatory reductions of greenhouse gas releases impact GRU's plans?
- What strategies are available to protect the community in the face of our rapidly changing energy future?

This first chapter discusses some of the more important findings of the EPAC review. Some of the topics discussed in this summary are crosscutting issues that appear in several of the chapters. This chapter integrates many of these materials.

[5] These are the rules for Prevention of Significant Deterioration (PSD) to existing air quality for sulfur dioxide, oxides of nitrogen, and particulate matter. Sulfur dioxide and oxides of nitrogen emission reductions achieved by the Deerhaven retrofit might balance the added sulfur dioxide and nitrogen oxides emissions from the new plant. PSD requirements for particulate matter could also be avoided in this manner, provided appropriate controls are included in the retrofit, but EPA has not announced details of PSD requirements for $PM_{2.5}$.

1.3 Major Findings

1.3.1 Avoidable Barriers to Conservation and Energy Efficiency Programs (Chapters 3 and 6)

Many studies have shown that "...the cheapest, easiest and fastest kilowatt we generate is the one we can save through efficiencies"[6]. Very large energy savings can be achieved by investing in energy efficiency and other conservation programs. Studies of states or regions have show that aggressive conservation and energy efficiency programs could yield energy savings far beyond what has yet been achieved in any program, including Florida.

The community requested that the GRU electric utility use more energy conservation measures to meet future increased demands. Conservation plays a role in GRU's proposals, but only a small role. GRU now has more than enough capacity to meet current needs, and realizes no economic benefits from implementing conservation under these circumstances. GRU will add about 7 MW in demand reduction over the next 10 years, 4 MW of which represents planned new programs. These programs will reduce the growth of demand in the local area by about 6.5% by the year 2014, compared to what it would have been with no conservation. Compared to other utilities, this is a small reduction. Austin Energy expects to reduce future demand increases by more than 20 % over the same interval while California utilities will reduce them by 55% to 59% (Chapter 6). **Figure 1.1** shows GRU's planned reductions and compares them to expected reductions by other utilities.

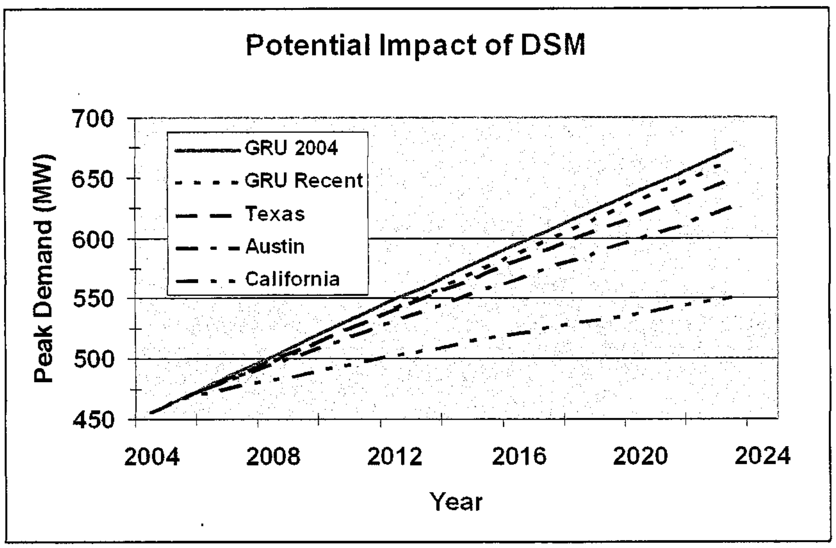


Figure 1.1 Peak demand increases over the next 10 years as originally forecast by GRU include some DSM (top line). GRU's planned DSM programs will achieve a total 6.5% reduction in demand growth ("GRU Recent"). Reductions GRU would achieve if it matched Texas, Austin Energy, or California targets are shown in this figure.

EPAC discovered significant barriers common to the electric utility industry that prevent optimum use of conservation techniques by many investor-owned utilities. Two of them are found in Gainesville. These barriers are self-imposed, and avoidable. The first is a

[6] Governor Jeb Bush 2001 "Powering the Future Energy Conference" cited by C. J. Barice in "Florida Energywise! A Strategy for Florida's Energy Future" The Final Report of the Florida Energy 2020 Study Commission, December 2001.

consequence the method chosen for calculating the annual transfer of money from the utility to the city. The second is a cost-effectiveness test chosen by GRU to evaluate specific conservation programs.

Fund Transfer Barriers

Conservation and energy efficiency programs are rarely greeted with enthusiasm by utility managers or owners, or even by city governments that own utilities. Why? The ability to obtain a profit (return on investment) and to collect enough revenue to cover fixed costs is tied to the volume of electricity sales for investor-owned utilities. This happens during the rate-setting process used by most utility commissions[7].

The Florida Public Service Commission does not regulate the City's method for calculating the amount of net GRU revenue transferred annually to the City. The City is free to choose any method to calculate the annual fund transfer. The City now uses a method similar to the one imposed on investor-owned utilities. The transfer amount is based on the volume of electricity sales, and it increases substantially if electric energy sales increase. The City loses income if sales volume drops. The formula also contains provisions for a bonus to the City if the utility generates extra electricity and sells it to other utilities.

This method of calculating City income produces a very strong incentive for GRU to generate and sell more energy, and an equally strong disincentive to adopt serious conservation and energy efficiency programs that could materially reduce the volume of electricity sales. This disincentive can give conservation and energy efficiency improvements a very low priority and lead to modest, poorly funded programs.

Gainesville could easily remove this disincentive by substituting a system that insulates the City transfer from sales volume decreases. Under such a system, the City decides in advance how much money will be transferred to its general fund each year. This amount remains fixed for the year. It is neither decreased nor increased in response to changes in the volume of sales that occur during the year. Such a system should also insure that the utility recovers its fixed costs, by establishing them in advance, and by insulating fixed costs collection from sales volume variations. This approach has been used elsewhere and is termed "revenue decoupling". The disincentive problem and its solutions are discussed in Chapter 7. The Austin, Texas, City Commission has achieved the same result simply by establishing a policy that conservation must be the first priority in meeting increased needs for energy.

RIM Test Barrier

The City has approved GRU's use of the "Rate Impact Measure" test (RIM test) to evaluate cost-effectiveness of proposed conservation or energy efficiency measures. This test says that no conservation or energy efficiency program that causes rates to be raised may be adopted by the utility. Every conservation program must pay for itself[8].

When applied exclusively, as in Gainesville, the RIM test forces a utility to reject conservation and energy efficiency investments that cost less than generation alternatives. In other words, the RIM text rejects DSM investments that reduce user needs for electricity more cheaply than

---

[7] The problem derives from the fact that new rates are set only once every 5 or six years. See Chapter 6 and Bachrach, D., S. Carter and S. Jaffe, "Do Portfolio Managers Have An *Inherent* Conflict of Interest with Energy Efficiency?" *The Electricity Journal*, Volume 17, Issue 8, October 2004, pp. 52-62.

[8] Applying such a test to new generators would disallow new generators because they raise rates by large amounts.

an additional generator could supply electricity to meet those needs. As a result, least cost DSM is screened out and energy bills are unnecessarily high.

Conservation programs require investments that could raise the rates for all customers, but they will raise them less than buying a new generator. If utility planners confine themselves only to conservation programs that pass a RIM test, they will end up choosing to build generators. This profound "pro-generator" bias of the RIM test restricts the planning process from the beginning by excluding conservation investments out of hand, forcing higher electricity costs on consumers.

Gainesville is free to invest money in any conservation and energy efficiency improvements it chooses. These can be included, along with new generators, in plans to serve increasing local needs[9]. No state law requires the City to adopt the RIM test with its strong pro-generator bias. Nothing requires the City to adopt the RIM test for any purpose. Nothing prevents us from choosing the least cost DSM option even if it raises rates for all ratepayers, just as we now chose the least cost new generator option though that involves raising rates for all ratepayers (rather than just those ratepayers responsible for the need for additional energy service). Investing in all the DSM that costs less than generation would help lower bills for low-income households. Other states do not rely so heavily on the RIM test.

Other RIM Test Problems

GRU does not actively seek new conservation or energy efficiency programs as part of its ongoing strategic planning efforts. These programs are reviewed and selected only when GRU is considering a new generator purchase, which it last did in 1994. All conservation programs now in effect were evaluated in 1994, and were compared with the generator then under consideration.

GRU could make conservation program selection and implementation an ongoing process. We could subject these programs to any cost-effectiveness test that we choose. We could also use a large suite of cost-effectiveness tests to illuminate different features of conservation programs. We could include costs or benefits like pollution reduction, economic benefits for local businesses, landfill costs (that could be avoided if wood is used as generator fuel), or any factors of interest to our community. None of these important considerations are captured by the RIM test.

1.3.2 Health Impacts of Pollution (Chapter 2)

EPAC reviewed the potential health effects of air pollution from GRU's existing and proposed generators. The most serious adverse air pollution effects are from fine particles emitted directly from the stacks (primary particulate matter) and those produced in the atmosphere from sulfur and nitrogen gas emissions (secondary particulate matter). These particles are collectively called $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter). They are well known to cause heart attacks, asthma attacks, episodes of difficult breathing among residents with emphysema or other chronic respiratory problems. Increased death rates from respiratory and cardiovascular disease, increased hospitalizations, and increased or more intense symptoms of respiratory or cardiovascular distress have all been associated with short-term

[9] GRU is not regulated under Florida Energy and Efficiency Conservation Act (FEECA) and therefore the Florida Public Service Commission places no demands on GRU as to how it evaluates conservation. FEECA requires *large* utilities to submit conservation programs for PSC approval. The commission as a matter of policy often uses a RIM test to review these programs.

exposures to elevated $PM_{2.5}$ well below the concentrations allowed by existing ambient air quality standards. Children, the elderly, asthmatics and those with other pre-existing diseases such as diabetes are more vulnerable to fine particulate pollution than other segments of the population.

Evidence about the health effects of fine particulates has prompted action among regulators. Reductions in the US 24-hour standard (65 µg/m3) and the US annual standard (15 µg/m3) are now under consideration. It is possible that a 4- to 8-hour standard could be added. California has already reduced its state annual standard to 12 µg/m3 and Canada began in 2000 to reduce its 24-hour standard to 30 µg/m3. All of this has occurred because of the serious health effects caused by $PM_{2.5}$.

Increasing scientific evidence shows that exposure to high concentrations of $PM_{2.5}$ can be very hazardous; and that in some locations, only short time exposures have adverse impacts on vulnerable individuals. This prompted EPAC to request that GRU use its modeling programs to explore the short-duration $PM_{2.5}$ air pollution concentration impacts of its generators. Separate model runs are needed for retrofitted Deerhaven Unit #2 and the proposed new generator to identify the $PM_{2.5}$ additions from each generator alone, and to evaluate air pollution impacts if no CFB generator is added. EPAC also requested separate model runs to evaluate fine particulate impacts from secondary particulate created by each solid-fuel generator.

1.3.3 Meeting the Challenge of Climate Change (Chapter 3)

Earth's climate is changing rapidly. There is little doubt among qualified scientists that Earth is getting warmer and the cause of the warming is the past and current releases of carbon dioxide into the atmosphere from burning fossil fuels. Average global temperatures increased steadily over the 20th century (**Figure 1.2**)[10]. It now appears possible that human societies may be unable to reduce heat-trapping greenhouse gas releases fast enough to keep the temperature rise from exceeding a total of 2 degrees C (3.6 degrees F) relative to pre-industrial times. The global warming to date has had very serious adverse impacts. Warming totaling the anticipated 2 degrees C is expected to result in widespread damage to Earth's ecosystems and the ability of human cultures to survive[11].

There is very strong pressure for mandatory caps on utility greenhouse gas emissions in the United States, and recent action in the U. S. Senate indicates that the outlines of a program to cap and ultimately reduce emissions of carbon dioxide and methane will be debated in 2006. Public opinion has shifted and polls indicate that the majority of Americans are concerned about global warming, and recognize the need for controls on greenhouse gas emissions.

While the federal government has yet to take decisive steps, states are leading the effort to reduce greenhouse gas emissions. Nineteen states are implementing or planning large investments in energy efficiency and renewable energy resources. Some have imposed emission caps on electric utilities, or are planning to impose them. Adoption of a national program to regulate greenhouse gas emissions in the United States is inevitable. It is impossible to predict when the regulatory programs will affect Florida, or exactly how they will regulate emissions. The electric utility industry will be among the first industries affected.

[10] During the peak of the last ice age, the average global temperature was only 5 degrees C less than the average global temperature in the 1950's. Between 1900 and 2000, the global average rose by 0.7 degrees C, much of it since the 1970's (Figure 1). The ten hottest years on record have occurred since 1990, three of them since 2000. An additional rise of 0.7 degrees C is already in the pipeline, due to past fossil carbon dioxide emissions.
[11] These are discussed in Chapter 3.

GRU's plan does not meet the impending challenges of our changing energy future. Moreover, GRU has not conducted a systematic analysis of the risks new regulations limiting fossil carbon dioxide emissions could bring to the utility and its customers, or evaluated alternative combinations of generators and conservation options in the context of those risks.

The following are among our most relevant findings:

- Coal is the fossil fuel that will be penalized most under greenhouse gas regulations, but GRU has no plans to address coming restrictions on releasing fossil carbon dioxide now obvious in the emerging regulatory framework[12].
- GRU does not plan to implement the aggressive conservation, efficiency, and demand management programs required to reduce greenhouse gas emissions[13].
- GRU's proposed carbon "offset" plan will not protect the utility from mandatory decreases in greenhouse gas emissions when regulations are imposed. None of the claimed GRU "offsets" conform to any existing or emerging offset requirements. The GRU approach is not designed to make real or substantial reductions in greenhouse gas emissions. GRU has not explored a more realistic option to certify and protect GRU's baseline against which future emissions reductions will be evaluated (See Chapter 3 Global Warming and Strategies to Meet It, and Chapter 4, Carbon Intensity, Offsets, and the Greenhouse Gas Fund).

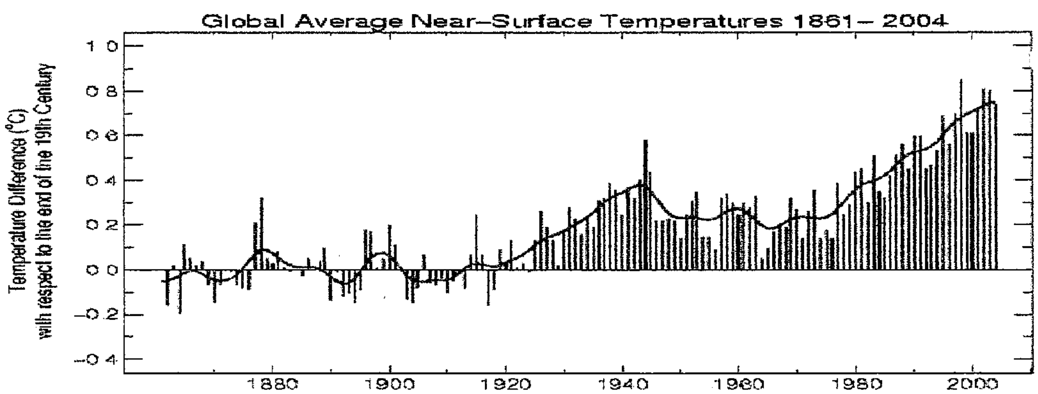


Figure 1.2. Average global temperatures are plotted here relative to the temperature in 1900, which was approximately 13.7 degrees C, and only 4.6 degrees C higher than during the peak of the last ice age.

Chapter 4 of this report discusses GRU's proposals to meet future greenhouse gas regulations. GRU plans to use coal and petroleum coke to produce over 90% of the electricity consumed in the local area. If implemented, these proposals will greatly increase GRU's fossil carbon

[12] Pressure to act to reduce and ultimately reverse the current annual increases in greenhouse gas emissions are building in the US. Mandatory carbon dioxide emission reductions from electric utilities are virtually certain. They are likely to take the form of cap-and-trade systems that allocate a utility's right to emit carbon dioxide and allow trading of these rights on a spot market.

[13] Other likely programs include subsidies for renewable energy sources, energy efficiency improvements and other measures to reduce electricity use.

dioxide emissions. GRU plans to protect itself from financial penalties under future regulation partly by relying on "offsets" for a total of 255,000 tons of carbon dioxide per year[14].

A greenhouse gas "offset" is an action that reduces emissions of greenhouse gases, or removes carbon dioxide from the atmosphere. For example, GRU counts growing pulpwood on City-owned land as an offset because the trees remove carbon dioxide from the air and convert it to plant tissue. GRU also counts past conservation activities by ratepayers and the repowering of the Kelly combined cycle plant as offsets. Carbon emission credits against carbon dioxide emissions from power plants exist only in the context of legally enforceable greenhouse gas regulations. An offset becomes an emission credit only after it has been certified as satisfying the eligibility rules incorporated in those regulations. EPAC found that none of the offsets now claimed by GRU would be acceptable under most of the regulations now under development.

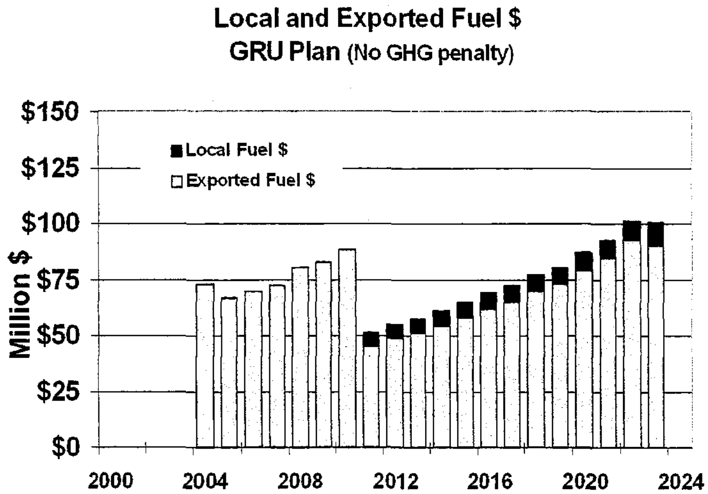
GRU's plans for a Greenhouse Gas Offset Fund have not been specified in detail, but some problems are already apparent. Compliance regulations being developed now incorporate a number of restrictions not met by the proposed GRU offsets. One is that all activities eligible for credits must be undertaken solely to supply greenhouse gas credits. Ongoing dual-purpose activities will be unacceptable, because they would occur without greenhouse gas regulations. This rules out silviculture, land development regulations, tree growth in conservation areas and many other local activities as candidates for offset carbon credits. EPAC concluded that the proposed offset strategy would not protect GRU from financial penalties when greenhouse emission reduction regulations are enacted.

1.3.4 Incorporating Biomass in GRU's Future (Chapter 8)

GRU proposes to use biomass to co-fire the new generator, but only for about 7.5% of fuel needed for the local electricity market[15]. Biomass is locally abundant and currently is our only locally available renewable fuel. Biomass produces no fossil carbon dioxide emissions[16]. Increasing biomass use in a small generator instead of building the large new coal generator could reduce GRU's total greenhouse gas emissions, thereby protecting the utility from greenhouse gas penalties under future regulations. The US DOE is currently supporting technologies for using wood and other renewable fuels. DOE might provide up to half of the capital cost for a state-of-the-art biomass generator, were the community to decide to build one, as an interim solution to the need for new capacity. This potential economic benefit was not considered in GRU planning.

EPAC explored the potential benefits of substituting a hypothetical 100-MW biomass generator[17] in place of the proposed 220-MW generator. EPAC's purpose was to illustrate the multiple benefits of greater biomass use. A new 100-MW unit and the existing GRU generating units would be able to meet the total energy consumption forecast by GRU through

[14] GRU claims offset credit for repowering a generator to make it more efficient, conservation by ratepayers, the use of landfill gas to fuel electricity generation, (inaccurately described as preventing the release of the heat-trapping gas methane) and the present of use of city land to grow pulpwood.
[15] Up to 13.7% of the fuel heat input to the proposed new circulating fluidized boiler could be derived from woody biomass, depending on the details of the design chosen by GRU.
[16] Biomass combustion produces small amounts of another greenhouse gas (nitrous oxide).
[17] EPAC did not model the hypothetical biomass generator on any existing design. It is used purely to illustrate potential advantages of biomass generation and to indicate whether the option deserves more detailed engineering and financial consideration.



approximately 2019. However, this does not mean that a 100-MW capacity addition will meet state requirements for reserve capacity[18].

Figure 1.3 - Fate of Fuel Dollars Under CFB Plan: Money exported out of state to pay for fossil fuel compared to that retained locally. The plotted data do not include a renewable fuel subsidy that could reduce fuel costs by about $3 million dollars.

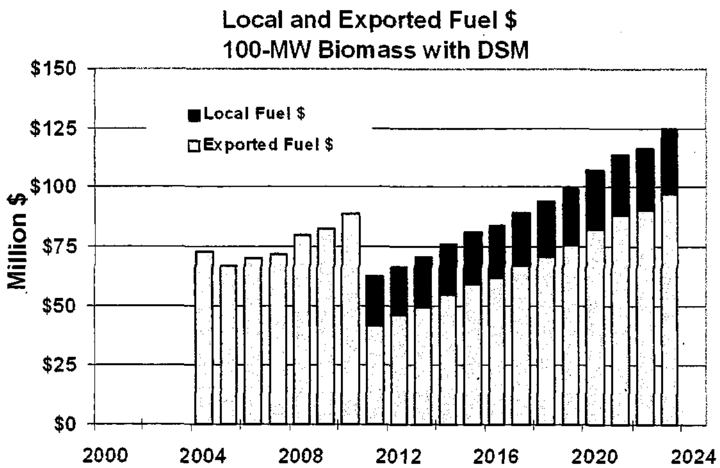


Figure 1.4 – Fate of Fuel Dollars under Biomass Plan: Money exported out of state to pay for fossil fuels compared with that retained in the local economy if GRU substitutes 100 MW of biomass to fuel electric energy generation for the proposed 220-MW CFB unit. The plotted data do not include a renewable fuel subsidy of 1.5 cents per kWh, which could reduce fuel costs by about $10 million per year.

Whether 100 MW of additional biomass-based capacity could meet needs would depend on peak energy demand reductions achieved through conservation or improved energy efficiency. Using biomass for 24% to 30% of local energy needs could deliver significant health benefits, benefits to the local economy, and function as a hedge against future greenhouse gas regulations. EPAC's analysis indicates that biomass fuel could cost slightly more than a solid fuel system if there are no limits on fossil carbon dioxide emissions, but would save money

[18] There are differences between "energy", "capacity", and "demand". *Energy* arrives through your electric meter; it is measured in kilowatt hours (kWh) or megawatt hours (MWh). *Capacity* is the maximum amount of electricity a generator or a collection of generators is capable of producing to supply a system; it is measured in megawatts (MW). *Demand* is the amount of electricity currently needed in a power system (like GRU and its service area) at any instant in time; also expressed in MW. The local GRU system's demand is higher in summer (because of many AC units) and lower in winter (because many heat with natural gas). The relationship between demand and energy is similar to the relationship between the speed a car may be moving (demand) and the number of miles it clocks up on the odometer (energy).

when greenhouse gas regulations are implemented. This benefit was not considered in GRU analyses.

1.3.5 Natural Gas Alternatives to the Solid Fuel Plan (Chapter 5)

GRU presented a cost comparison of its solid fuel plan with two hypothetical alternatives based entirely on natural gas in December 2004. Because natural gas is extremely expensive, neither of these was offered as a serious alternative to the plan GRU has proposed. GRU used a model to simulate the use of two alternative systems that use natural gas to supply anticipated increases in local energy needs.

EPAC found that these two new "alternatives" are virtually identical to the solid-fuel plan in all important respects, except that they used expensive natural gas to meet future needs, instead of cheap coal and petroleum coke. The simulations therefore confirmed that the solid fuel system is cheaper than the alternatives simulated, but this is due exclusively to large differences in coal and gas costs, a difference that GRU projected far into the future.

GRU conducted sensitivity analyses to see whether the high costs of fossil fuel carbon dioxide emissions under a hypothetical GHG regulation could change the conclusion that the solid fuel system is cheaper than systems using natural gas. This sensitivity analysis is not a risk analysis. GRU did not compare its plant to practicable alternatives such as aggressive conservation, use of biomass fuel, and a cautious incremental approach to adding capacity. The GRU evaluation methodology is not amendable to comparisons with genuinely different approaches to meeting community electricity needs.

1.3.6 Off-System Sales (Chapter 7)

GRU's proposal includes significant excess energy capacity through 2023. GRU plans to use this excess capacity to generate electricity for export to other utilities in the state. Although the ability to generate and sell excess energy is described as key to the financial success of the proposal, GRU has not disclosed details of this part of its plan to the community. Critical details needed to evaluate the impact of off-system sallies include the amount of energy that will be generated for export, the amount of money GRU would earn from these sales, or the local environmental impact of excess power generation. Consequently, EPAC evaluated the opportunities to generate excess electricity if the two solid-fuel plants were operating, and reviewed the air impacts and effects this might have.

Generating electricity for off-system sales will certainly increase local air pollution. The capacity of the two solid-fuel units (Deerhaven 2 and the new generator) is so large that local needs will not consume their entire production except during a few hours each year for the first 4 or 5 years of operation. For example, GRU projections suggest that in 2015, the base units will supply about 98% of all the locally energy consumed (**Figure 1.5**). We assume that the two units will operate full time most of the year to produce energy for off system sales as well as local needs. **Figure 1.6** shows the increase in pollution that will result if GRU uses all spare capacity to generate energy for this purpose. (The pollution due to generating electricity for off-system sale was not considered in the models GRU used to evaluate pollution impacts discussed in Chapter 2 of this report.) **Figure 1.6** shows the extra sulfur dioxide and nitrogen oxide pollution that is caused by excess energy generation in the year 2015. The total amounts produced in each hour of the day are based on assumptions about the daily load supplied by GRU.

Will GRU continue to have a ready market for all the excess electric energy it can produce through and beyond 2023? If so, then GRU might be able to sell large amounts of coal-based excess energy and reap significant increases in net revenue from the sales. EPAC estimates that over the 13-year interval modeled by the EGEAS program, these two units could bring in a total of between $260 and $345 million dollars in net revenue[19], which would be around half of the service on the debt assumed to retrofit Deerhaven Unit #2 and build the new CFB generator. These figures assume that trends apparent in 2003 are projected through 2023, and that there will be a continuing need for cheap, coal-based energy. Such projections are based on the assumption that neither the federal government nor the state will regulate greenhouse gas emissions, or take any steps to reduce energy use in the state in order to reduce those emissions. Given that large reductions in state energy use that are achievable through a vigorous mandatory energy conservation program, the assumptions underlying the plan to sell excess energy must be questioned[20].

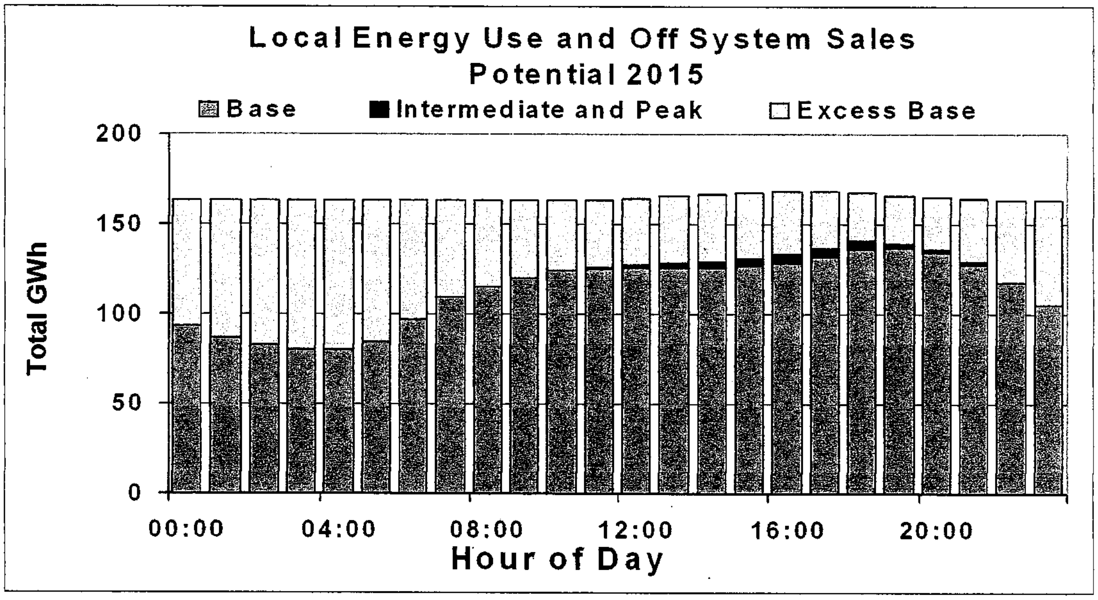


Figure 1.5 Energy from base units and other units needed to supply consumption in the local area and the total base capacity available. Each bar corresponds to the total GWh sold at that hour throughout the entire year. All but 2% of total local energy needs could be supplied by the two base units, leaving 1,000 GWh left over for off-system sales.

[19] Assumes an 85% average capacity factor, and $15 to $20 net revenue per MWh of energy sold. More income would be generated if GRU also rented capacity to other utilities via a purchase power agreement, as they currently do with the City of Starke.

[20] ~~See Chapter 5, Off-System Sales, Chapter 2 on "Pollution and Health Impacts", Chapter 3, "The Global Climate~~ Crisis and Strategies to Meet It", and Chapter 5, "Off System Sales".

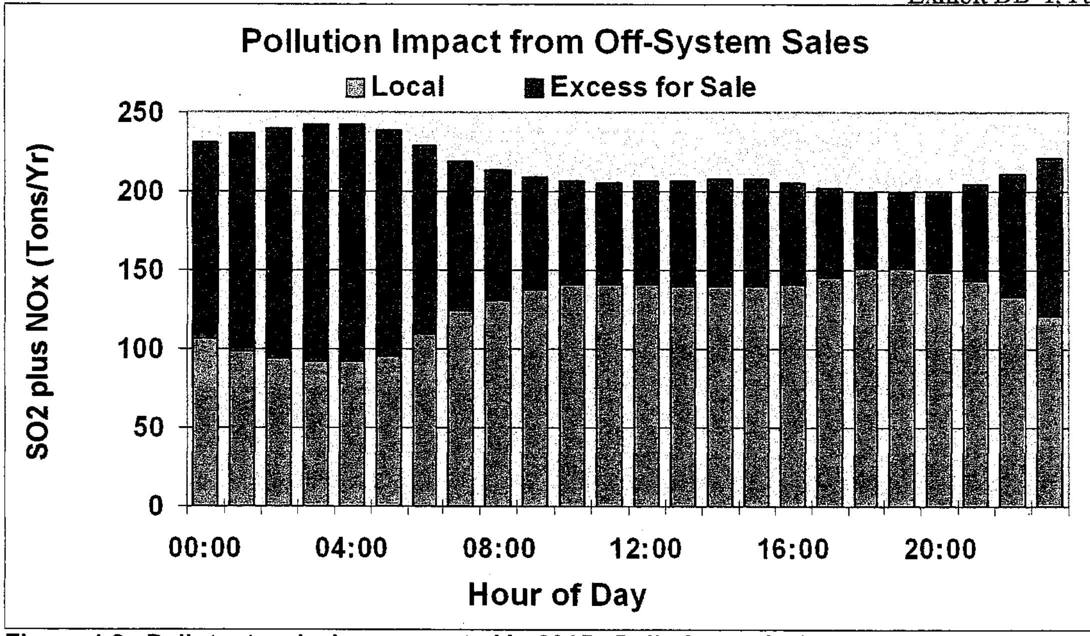


Figure 1.6 Pollutant emissions expected in 2015. Pollution emissions expected if the two solid-fuel units supply local energy needs (lower part of each bar) and generate electricity for export to other utilities (top part of each bar). Sulfur dioxide and oxides of nitrogen contribute to fine particulate pollution. This plot assumes all spare capacity is devoted to generating electricity for off-system sales. It does not show the times when the base units are off line for scheduled maintenance.

1.4 Policy Issues: What is the proper role of a municipally-owned electric utility?

Municipal utilities in Florida are free to operate differently from more closely regulated investor-owned utilities. EPAC's attempts to understand the constraints that guided GRU strategists in developing their proposal confirmed that GRU has adopted some policies similar to those of investor-owned utilities that are regulated by a state utility commission. This finding raised important policy questions:

- Should GRU use the planning methods, goals, and approaches of an investor-owned utility that merely happens to belong to a city government?
- Alternatively, could GRU's planning process include broader goals and important responsibilities to its wider community of owners?

How has GRU's approach resembled that of an investor-owned utility and what differences does this approach make? The differences in these two approaches are illustrated by the different ways EPAC and GRU approached questions about the air pollution produced by its generators. GRU focused on satisfying air quality standards, and used models to study how its plants would add pollutants to local air. The study reports were oriented toward persuading the community that its proposed new systems would meet existing ambient air quality standards.

EPAC focused on the potential effects of air pollution on community health, and confirmed that existing air quality standards for fine particulate matter are widely known to be inadequate to protect public health. EPAC also found that the new plant could have significant adverse health impacts if it adds large amounts of fine particulate matter to ground level air, even if those additions last only for a short time—a few hours or less.

EPAC requested that GRU use its models to provide more details about short-term impacts on local air, and individually explore impacts of the fine particulate air pollution of each of its proposals: retrofitting the existing plant, and building a new one. EPAC also requested that new modeling include corrections to some emission rate underestimates GRU's consultants used in their models, but these were not performed. GRU did authorize using the models to produce estimates of the very short term impacts of power plant emissions on local levels of fine particulate matter. These proved very helpful.

Other policy questions turned up in a number of EPAC's inquiries, but these are not discussed as such in most of the following chapters. Two exceptions are Chapter 5 on Alternative Systems, and Chapter 6 on Conservation and Energy Efficiency. Chapter 5 discusses policy aspects of evaluating alternatives, and Chapter 6 discusses the policy implications of the roles of *GRU and the City Commission in selecting conservation and energy efficiency measures.*

1.5 Final Comments

The energy industry is presently undergoing enormous change, and more dramatic changes are yet to come. In the words of Juan Garza, General Manager of Austin Electric[21]:

"Today the electric utility industry is being rocked by change, the magnitude and swiftness of which the industry has not witnessed since its birth. This change will completely redefine the electric industry over the course of the next two decades. I believe that utilities that prepare for this change will be part of a new and dynamic energy future. I also believe that those utilities that cling solely to the past, will find themselves rendered obsolete and irrelevant by this change. It is my intention for Austin Energy to be a part of the new energy future and to play an important and significant role in defining it."

EPAC's review of GRU's proposals has found many areas where GRU's approach fails to respond to new challenges, and appears to embrace the old "burn to earn" model of an electric utility in the community. Greater responsiveness to the changes in the energy environment is possible, and could be usefully explored.

[21] "Austin Energy's Strategic Plan", December 2003. Available for download at: http://www.austinenergy.com/About%20Us/Newsroom/Reports/strategicPlan.pdf

Chapter 1, Appendix 1: History of the EPAC Review

In September 2003 Gainesville Regional Utilities (GRU), a municipal utility owned by the City of Gainesville Florida, began a series of public meetings to present information about the increasing demand for electric energy in its native service area[22]. In these meetings, the utility offered four alternative approaches to satisfying this demand for the interval 2003 through 2022. A document describing these alternatives and the planning process[23] used to select them was presented to the Gainesville City Commission on December 15. After several meetings and discussions with commissioners, GRU refined the options, eliminated three of them, and submitted a new plan to the City Commission featuring only one of the original four in February 2004[24].

Gainesville and the urbanized area surrounding it contain most of the population of Alachua County. The Alachua County Environmental Protection Advisory Committee (EPAC) is a committee of citizens appointed by the Alachua County Commission to advise them about environmental issues.

GRU's Deerhaven Unit #2 is Alachua County's largest point source of atmospheric pollution. It is fueled by coal combustion. The idea of adding a second coal-fired plant to the GRU fleet was greeted with caution by many EPAC members, so they voted to request the County Commission to authorize them to undertake a systematic review of the potential environmental impacts of the new plant and other features of the Integrated Resource Plan under development by GRU. This request was approved, and the review began formally in January 2004.

The review documented in these pages has been conducted by members of EPAC and an extremely knowledgeable and helpful volunteer, Dr. David Harlos, who has considerable expertise in environmental health and air pollution.

EPAC members have reviewed the documents provided to the public by GRU, as well as many additional GRU documents, reports, and similar publications. GRU staff has frequently met with EPAC members, and shown great patience and courtesy in dealing with the many requests members made while conducting the reviewing. EPAC members were helped by many local experts who shared their views, research papers, and other materials with us.

Members also reviewed the public press and, articles from the professional literature on health, climate change, and utility regulation, planning and economics. Government reports and the publications of a number of groups that conduct research on the electric utility industry were an important source of information. The reports available from the web sites of the Energy Foundation, the California Public Utilities Commission, the California Energy Commission, the Regional Greenhouse Gas Initiative, the Electric Power Research Institute, and the American Council for an Energy Efficient Economy were especially helpful, as were those from a number of consulting firms that do research for these organizations, and for State Public Interest Groups, utility regulators, and municipal or investor owned utilities.

---

[22] Gainesville is in Alachua County, Florida. The native service area of Gainesville Regional Utilities includes retail customers in the City of Gainesville, Florida, plus retail customers in the urban fringe surrounding the city. In addition, GRU supplies wholesale electricity to the City of Alachua and Clay Electric Cooperative for resale to customers, most of whom are also residents of Alachua County.

[23] "Alternatives for Meeting Gainesville's Electrical Needs Through 2022: Base Studies and Preliminary Findings", Gainesville Regional Utilities, December 2003.

[24] "Meeting Electrical Needs Through 2022: Alternatives Update and Modification, Gainesville Regional Utilities Presentation to the City Commission, February 9, 2004.

DOCKET NO. 060035-EI
Fact Sheet
Ex. DD2
p. 1 of 4

UF UNIVERSITY of FLORIDA
IFAS Extension

WOOD to ENERGY

Sustainability of Wood: How Much Do We Have and Where Is It Coming From?

Resources that can be regenerated without depleting the underlying stock are considered "renewable". Examples of renewable resources include trees, along with water, wind, and sunlight. However, if converting wood to power is to be economically viable and environmentally responsible, forests must be properly managed to ensure that bioenergy projects do not use more wood than is sustainably available. A key component to sustainable forestry is insuring that forests are not depleted by over-harvesting. This means that wood removal cannot exceed wood growth in the long term. How can we determine what amount of wood is available sustainably?

This quantity depends on the productivity of local forests and land use practices. Proper management of the forest resource can be split into two categories. First, forest managers must make accurate measurements of how much wood is available without harming the forests. Second, care must be taken to use fuel wood as efficiently as possible. In many cases, this means using wood that is actually waste from other timber activities. In this fact sheet, we discuss each of these factors in the context of the southern United States.

Sustainability in the Southern United States:

The U.S. produces over 25 percent of the world's total industrial timber, and is the second largest exporter of timber products after Canada. Most of this timber is produced in the South (Wear & Greis, 2002). In spite of these high rates of production, average wood growth in the southern U.S. continues to surpass the amount of wood harvested. Future timber growth is projected to be greater than harvests in response to projected demands for timber (Adams *et al.*, 2003). That means that researchers are predicting that forests will be growing faster than people are using wood. At local levels, sustainable forest management can provide woody biomass for energy along with other wood products.

Nationwide, the volume of timber has increased over the past 50 years from 616 to 856 billion cubic feet, mostly from conversion of agricultural lands to forest (Smith *et al.*, 2004). The most recent available FIA data indicates net growth[1] of growing stock[2] was greater than harvest for ten of the thirteen southern US states (Figure 1). In other words, in ten southern states, there is more forest today than there was fifty years ago.

Available Data on US Forests:
The Forest Inventory and Analysis (FIA) program of the USDA Forest Service was mandated by the McSweeney-McNary Forest Research Act of 1928 and the Forest and Rangeland Renewable Resources Planning Act of 1974 to monitor the quantity and quality of timber on the Nation's forest lands. FIA collects data on sample plots annually within each US state. FIA data, including forestland area, timber growth, and harvest volumes, can be accessed from http://ncrs2.fs.fed.us/4801/timber

[1] "Net growth" means growth before harvests minus mortality.
[2] "A growing-stock tree is a live tree of commercial species that either contains or is capable of producing at least one 12-foot or two 8-foot logs in the saw-log portion." (Bentley and Johnson, 2003).

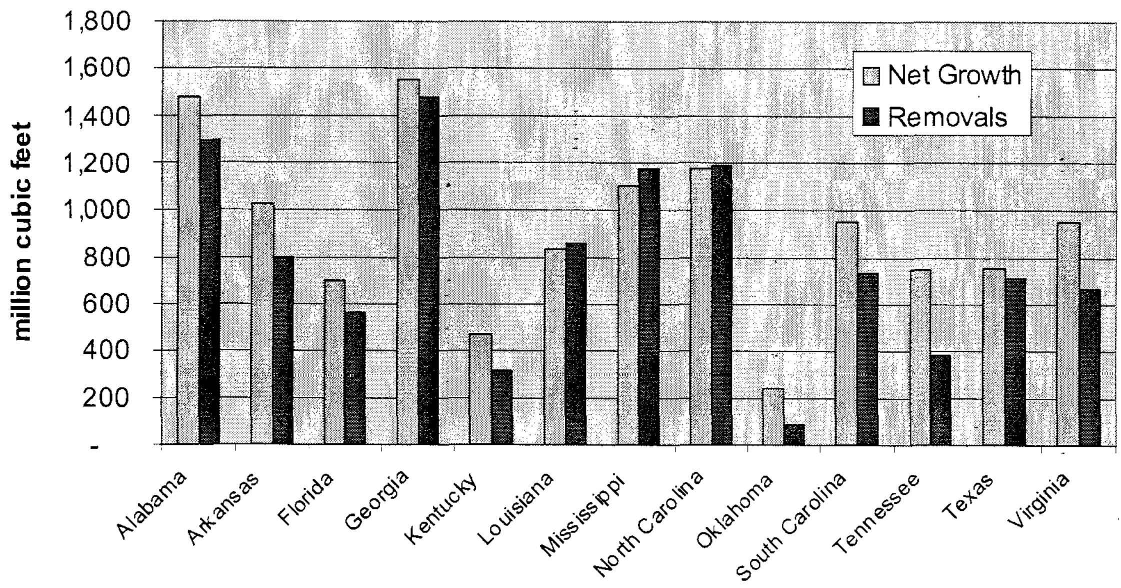


Figure 1. Net growth and removals of growing stock of thirteen southeastern US states. Accessed from FIA Mapmaker version 2.1 on July 19th, 2006.

Power Production as a Secondary Use for Wood:

Waste wood and industry by-products are good candidates for woody biomass sources because they are inexpensive and do not represent added pressure on local forests. Though county-level forest yields vary widely, FIA data from over 1,600 counties and parishes in the Southeast indicates an average of over 14,000 dry tons of forestry residues is sustainably available per county annually, the equivalent of about 2.0 MW of electricity per county per year. Potential sources of waste wood are discussed below.

Sawtimber:

Local forests in which trees are grown for sawtimber produce waste wood in two ways. The first is from forest thinning. Trees for sawtimber are often planted at high densities so that they produce straight, knotless wood. However, as the trees grow, they require more room and are thinned accordingly. For example, the trees may originally be planted at a density of 700 trees per acre. After twelve years, these trees may be thinned to a density of 400 trees per acre. At each thinning, the cut trees can be made available for power production.

The second source of waste wood from sawtimber operations comes during the harvesting of the timber. Stumps and branches that are too small for lumber production are often left on the harvest site or otherwise disposed of. These too can be used for producing energy. Any changes in local timber production will cause changes in the amount of waste wood available for power production. For example a shift from pulp wood production for paper—which can use smaller trees—to sawtimber production would cause an increase in wood from thinnings available for energy production during the forest's lifetime.

Habitat Restoration and Fuelwood Control:

Wood is also available from the management of natural areas and can be used for energy production. For example, managing a natural area to maintain a certain kind of habitat (e.g. longleaf pine) requires removing certain species of trees that are not naturally found in that habitat. These removed trees can become a source of fuel for a biomass power plant.

Secondly, many forests require fire management. In pristine forests, naturally occurring fires keep the amount of woody biomass—such as dead wood and underbrush—under control. Forest managers can mimic this natural process with prescribed burns or by removing some of the woody biomass from the forest through mechanical methods. In the latter case, the woody biomass removed from the forest can be available for energy production. Thinning may be particularly preferable for forests in the wildland-urban interface where the risk of fire must be reduced to protect nearby homes.

Urban Wood Waste

Wood removed from residential and business properties, such as trimmed limbs or unwanted trees, can also be a significant source of wood for energy production. Research has shown that there are about 0.1 dry tons of urban wood waste (city tree trimmings and storm debris) per person per year (Wiltsee, 1998). For an average county population size in the southern US of about 75,000, this is equivalent to 9,000 dry tons of wood, which can provide enough power to supply 400-900 homes per year. Many people living in the southern United States can attest to the increase in yard waste that results from storms felling trees and limbs. Since people currently pay—either to private landscapers or within their utilities bill— to have their yard waste removed, collecting this waste as a source of fuel can become an economically viable operation.

Phytoremediation

The term "phytoremediation" describes the process of using trees to clean up sites with contaminated soil or water. Trees planted in these areas extract the contaminants, such as arsenic and nitrates, from the soil as the trees grow. The trees, along with the contaminants they contain, can then be removed from the site and used for energy production. Notably, wood from phytoremediation projects contains lower amounts of these contaminants than what is found in coal.

Commercially Available Wood

The previous four sections of this fact sheet all involve the use of waste wood from other processes. Another potential source of wood for energy production is small diameter wood from plantations. Under conditions of low-priced wood and/or high-priced energy, about 8 million dry tons of wood currently grown for conventional timber products could be allocated to energy production (Perlack *et al.*, 2005). This is enough energy for about 1.2 gigawatts or 500,000 to 1,000,000 homes annually.

More Aspects of Sustainable Forestry

Other aspects of sustainable forestry in addition to sustained yield include biodiversity, ecosystem health, social values, and soil quality. Various governmental and nongovernmental agencies are dedicated to fostering sustainable forest management. One option for communities that want to ensure that biomass is a sustainable source is to make sure it has been "forest certified" from an independent forest auditor.

Find Out More

You can find more general information about bioenergy at the Renewable Energy Policy Project (http://www.repp.org/bioenergy/index.html). More information about forest thinning for sawtimber production is available in a paper by David South of Auburn University (http://www.forestry.auburn.edu/sfnmc/class/density.htm). And more information on sustainable forest management and forest certification can be found at the USDA Forest Service, (http://www.na.fs.fed.us/sustainability), the Forest Stewardship Council, (www.fsc.org); and Abundant Forests (www.abundantforests.org).

References

Adams, D.M., Alig, R., Brooks, D., Butler, J., Durbak, I., Haynes, R. W., McKeever, D., Mills, J. R.. 2003. An Analysis of the Timber Situation in the United States: 1952 to 2050. Report Number PNW-GTR-560. USDA FS. Portland, OR.

Bellemar, D.. 2003. What is a Megawatt? Retrieved 7-13-2006 from http://www.utilipoint.com/issuealert/article.asp?id=1728.

Perlack, R., Wright, L., Turhollow, A. F., Graham, R. L., Stokes, B., Erback, D.. 2005. Biomass as feedstock for a bioenergy and bioproducts industry: the technical feasibility of a billion-ton annual supply. Report Number ORNL/TM-2005/66. 1-78. Oak Ridge National Laboratory. Oak Ridge, TN.

Smith, W., Miles, P., Vissage, J., Pugh, S.. 2004. Forest Resources of the United States, 2002. Report Number GTR-241. USDA Forest Service, North Central Research Station. St. Paul, Minnesota.

Wear, D., Greis, J.. 2002. The Southern forest resource assessment summary report. Report Number SRS-54. 1-103. Southern Research Station. Asheville, NC.

Wiltsee, G., 1998. Urban wood waste resource assessment. ; National Renewable Energy Laboratory, Golden, CO.

Docket 060635-EU
Biomass Economic Report
Ex. 003
p. 1 of 5

UF UNIVERSITY of FLORIDA
IFAS Extension

edis

Economic Impacts of the Forest Industry in Florida, 2003[1]

Alan W. Hodges, W. David Mulkey, Janaki R. Alavalapati, and Douglas R. Carter[2]

The following is the abstract of a much larger report, which is only available in pdf format. To access the complete report, please click here .

Executive Summary

Florida has over 16 million acres or 25 thousand square miles of forests, representing nearly half of the state's land area. Forests in Florida are managed to produce a variety of wood and fiber products, with about 650 million cubic feet of roundwood harvested annually. These forests also support outdoor recreational opportunities for residents and millions of visitors to the state, and provide important non-market environmental services such as biodiversity, hydrologic function, and mitigation of global climate change through sequestering atmospheric carbon.

A study was conducted to assess the economic impacts of the forest products industry in the state of Florida, in order to better understand its role and contribution to the regional economy. A mail survey was used to collect information on product sales, employment, regional trade, and types of products and services offered by forest industry firms. Major sectors of the industry surveyed were landowners, forest product manufacturing mills, and forestry service businesses such as loggers, management consultants, trucking, and forest tree nurseries. Mail surveys were supplemented by personal interviews with mill managers, and other secondary statistics. A total of 615 usable questionnaires were received, representing an overall response rate of 19 percent. Survey respondents reported total sales of $2.54 billion (Bn) in 2003 and employment of 8,436 fulltime and part-time or seasonal employees (Table ES-1). Assuming the survey data were a representative sample of the industry, these results were extrapolated to estimate a total value of industry sales at $7.78Bn, including $6.37Bn by manufacturers, $1.02Bn by service firms, and $382 million (Mn) by landowners. Total employment in the industry was estimated at around 30 thousand jobs.

Values were estimated for specific forest products and services. Among manufactured products, values in excess of $100 million were obtained for pulp ($2.18 Bn), paper/paperboard ($1.78 Bn), preservative-treated wood ($859 Mn), dimension lumber ($388 Mn), plywood ($365 Mn), wood chemicals ($245Mn), chipped wood ($185 Mn), and mulch/shavings ($123 Mn). Revenues for forestry services included timber harvesting ($615 Mn), timber trucking ($113 Mn), forest thinning ($107 Mn), tree trimming and removal ($61 Mn), and site preparation ($48 Mn). Values for forest products sold by landowners included pulpwood ($80 Mn), pine straw ($79 Mn), chip-and-saw logs ($62 Mn), and sawtimber logs ($37 Mn).

The forest products industry also produces a significant amount of electric power and heat energy to meet its energy needs for manufacturing processes, through utilization of residuals and byproducts, contributing to energy sustainability through reliance on locally renewable resources. The industry increasingly utilizes post-consumer recycled fiber sources for paper manufacturing, which reduces the dependence upon forests for virgin wood fiber.

1

Docket 060675-EU
Biomass Economic Report
Ex DD3
p. 2 of 5

Regionally in Florida, the value of all forest products and services produced was $3.8Bn (49%) in the northeast, $2.01Bn (26%) in the central, $1.21Bn (16%) in the northwest, and $695Mn (9%) in the south (Figure 1). Exports of forest products outside the state to domestic and international markets represented 50 percent of total industry sales, and within Florida, 23 percent of total sales were to the central region, 15 percent to the northeast, 8 percent to the south, and 4 percent to the northwest.

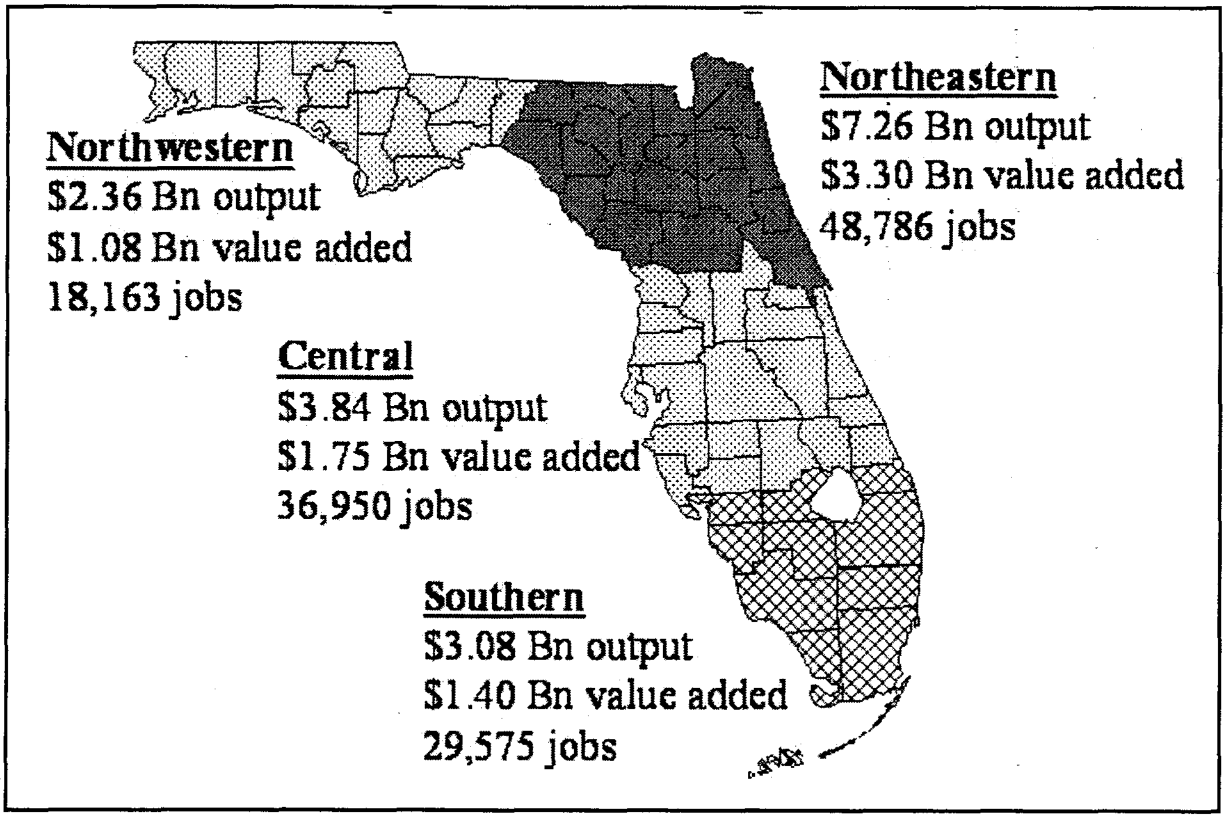


Figure 1. Economic impacts of the forest industry in Florida regions.

Total economic impacts of the forest products industry were evaluated using a regional input-output model developed with the *Implan* software system and associated databases for Florida counties (MIG, Inc). These models represent the structure of an economy in terms of linkages between industry sectors, households and governments institutions. The model accounts for commodity production, employment, final demand, transfer payments, taxes, capital investment, and regional trade (imports and exports). Multipliers from the model enable estimation of the change in total regional economic activity resulting from output or employment of a particular sector that is attributable to business activity by input supplier industries (indirect effects) and employee household spending (induced effects). Values of total sales estimated for specific products and services were entered into *Implan* for 12 separate forest products industry sectors to calculate total impacts.

Total economic impacts of the Florida forest industry are indicated in Table ES-2 . Total output or sales impacts of the forest products industry in Florida in 2003 were estimated at $16.63 Bn, including $8.84 Bn in the forestry and forest product sector and an additional $7.70 Bn in other industry sectors. This was comprised of $7.78 Bn in direct sales, plus $3.09 Bn in indirect impacts associated with activity in supplier businesses, and $5.67 Bn in activity due to spending by industry employees. Within the forest industry, output impacts were $1.65 Bn in forestry and natural resources and $7.19 Bn in forest product manufacturing. Total employment impacts were 133,475 jobs, with 48,930 in the forest sector and 84,545 in other industry sectors. Total value added impacts were $7.52 Bn, including labor income of $4.92 Bn, other property-related income of $2.02 Bn, and indirect business taxes paid to local, state and federal governments of $581 Mn. Fiscal impacts on total tax collections by governments were estimated at $1.75 Bn, including sales taxes, property taxes, payroll taxes and personal and business income taxes. The value added impact indicates the net contribution of personal and business income to the regional economy. This value for the forest industry represents approximately 1.53 percent of the gross regional product of the Florida economy ($490 Bn).

2

DOCKET NO. 060635-EL
~~Abstract~~ Biomass Economic Report
Ex DD3
p. 3 of 5

Economic impacts were estimated for Florida counties and regions based on their share of total state economic activity in the forest products sector. Total economic impacts are indicated for four regions of the state in Figure 1 . The top ten Florida counties in terms of output impacts were Taylor ($1.94 Bn), Miami-Dade ($1.89 Bn), Duval ($1.71 Bn), Putnam ($1.08 Bn), Escambia ($1.05 Bn), Hillsborough ($1.00 Bn), Nassau ($973 Mn), Polk ($684 Mn), Orange ($595 Mn), and Bay ($502 Mn).

Recreation and tourism values associated with Florida forests were also evaluated in this report from secondary information sources. According to US Fish & Wildlife Service surveys, wildlife-related recreational activity, including hunting, fishing and wildlife viewing, accounted for total expenditures in Florida in 2001 estimated at $6.05 Bn, including $2.89 Bn for trip costs for fuel, lodging, meals, etc., and $3.17 Bn for recreational equipment purchased (e.g. boats, guns), with $1.20 Bn spent by Florida visitors. Of course, not all wildlife-related recreational activity is directly attributable to the forest resource; however, most of the hunting and wildlife watching takes place in forested ecosystems.

Tourism is the largest and most well known sector of the Florida economy, and forested landscapes provide environmental amenities that support this industry, particularly for the growing eco-tourism market. Visitor spending of around $47 Bn in Florida in 2000 had an estimated output impact of $117 Bn. Surveys indicate that over half of Florida visitors engage in some type of nature-based activity during their visit, and a study by the USDA-Forest Service indicated that 19 to 33 percent of total travel and tourism activity in the southern U.S. is attributable to outdoor recreation. Using the lower bound (19%) together with data on the total value of Florida tourism, it is estimated that outdoor recreation in the state had a total economic impact of $22.3 Bn in output, $14.72 Bn in value added, and 332 thousand jobs. Again, some share of this may be appropriately attributed specifically to forest ecosystems.

In addition to these commercial commodity and recreational use values associated with forests in Florida, there is an array of non-marketed environmental services that are important to recognize, although they may not be readily quantified. Some of the environmental services of forests include surface and ground water storage, purification of air and water, mitigation of droughts and floods, stabilization of climate and moderation of extreme weather events, generation and preservation of soils, detoxification and decomposition of wastes, cycling and movement of nutrients, control of agricultural pests, provision of wildlife habitat, and maintenance of biodiversity. An estimated 5.8 million tons of carbon are sequestered annually by Florida forests. Markets for this service for trading of pollution emission credits are being established (e.g. Chicago Climate Exchange). The avoided costs for pollution abatement may be conservatively estimated at a price of $5 per ton Carbon, which would indicate a total value of $29 million annually for this environmental service.

Forests in Florida also provide numerous amenities or quality of life values. Published studies have shown that properties landscaped with trees and other attractive vegetation may add approximately 6 to 10 percent to the value of homes purchased. Thus, forests contribute to the large market in Florida for real estate development. Some additional non-market benefits to human communities from forests include support of rural life values, provision of character building opportunities, support of national identity/ideals, heritage, research and educational values. Finally, forests provide personal, psychic and aesthetic benefits such as job satisfaction, scenic views, therapeutic and physical health values, intrinsic existence values, religious and spiritual values.

Tables

Table ES-1. Florida forest industry groups surveyed, response rates, and reported and estimated sales and employment in 2003.

Survey Group	Number Firms Targeted	Number Respondents	Response Rate	Reported Sales ($Mn)	Reported Employment (full & part time)	Expanded Sales ($Mn)	Expanded Employment (jobs)
Landowners	2,460	474	19.3%	73.7	729	382.4	3,781
Manufacturers	175	65	37.1%	2,366.3	6,807	6,370.9	18,327

3

Docket No 060635-EI
Biomass Economic Impact
Ex DD3
p. 495

Forestry Services	680	76	11.2%	114.4	901	1,023.8	8,057
Total	3,315	615	18.6%	2,554.4	8,436	7,777.0	30,164

Table ES-2. Total economic impacts of the forest industry in Florida, by industry group and sector, 2003.

Industry Sector	Output Impact ($Mn)	Employment Impact (jobs)	Value Added Impact ($Mn)
Forestry & Forestry Products	8,835	48,930	2,709
Forestry & Natural Resources	1,646	24,834	835
Logging	722	5,082	364
Forest nurseries & timber tracts	406	1,165	185
Agriculture & forestry support activities	449	17,534	244
Forest Products Manufacturing	7,189	24,096	1,875
Pulp mills	2,181	4,916	502
Paper & paperboard mills	1,781	4,197	594
Wood preservation	931	2,816	131
Sawmills	955	5,271	229
Veneer & plywood manufacturing	388	2,394	117
Other miscellaneous chemical product manufacturing	255	828	65
Miscellaneous wood product manufacturing	86	706	28
Millwork, including flooring	10	125	5
Reconstituted wood product manufacturing	6	23	2
Other Industry Sectors	7,699	84,545	4,814
Total	16,534	133,475	7,523

Footnotes

1. This is EDIS document FE538, a publication of the Department of Food and Resource Economics, Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida, Gainesville, FL. Published February 2005. Please visit the EDIS website at http://edis.ifas.ufl.edu.

2. Alan W. Hodges, Associate-In, Department of Food and Resource Economics; W. David Mulkey, Professor; Department of Food and Resource Economics; Janaki R. Alavalapati, Associate Professor, School of Forest Resources and Conservation; Douglas R. Carter, Associate Professor, School of Forest Resources and Conservation; and Clyde F. Kiker, Professor, Department of Food and Resource Economics, Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida, Gainesville, FL.

4

Docket No. 060635-EU
Biomass Economic Report
Ex. DD3
p. 5 of 5

discrimination with respect to race, creed, color, religion, age, disability, sex, sexual orientation, marital status, national origin, political opinions or affiliations. For more information on obtaining other extension publications, contact your county Cooperative Extension service.

U.S. Department of Agriculture, Cooperative Extension Service, University of Florida, IFAS, Florida A. & M. University Cooperative Extension Program, and Boards of County Commissioners Cooperating. Larry Arrington, Dean.

Copyright Information

5

Woody Biomass Fuel Available to Tallahassee

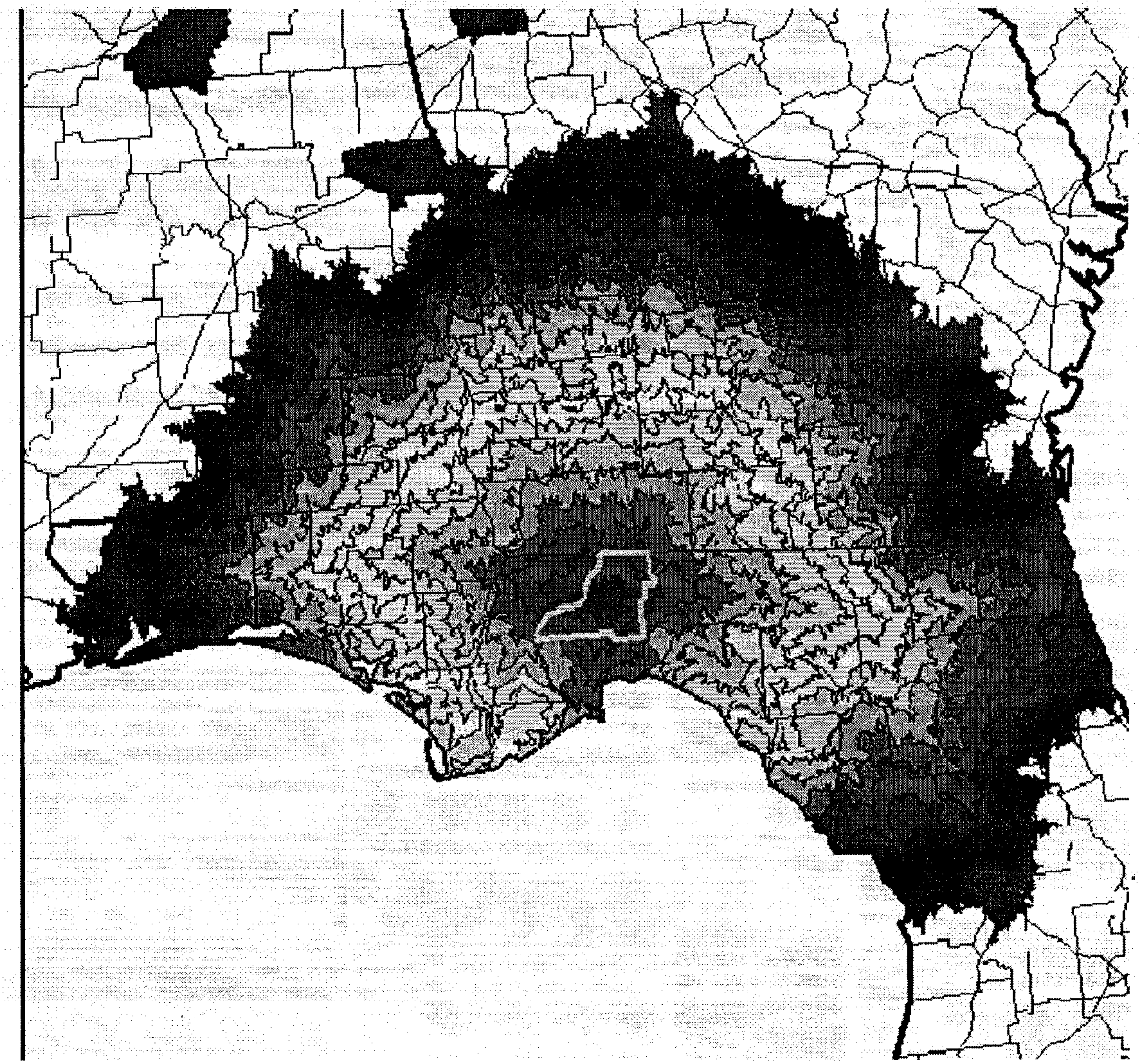
Presentation to Tallahassee City Commission by Dian Deevey

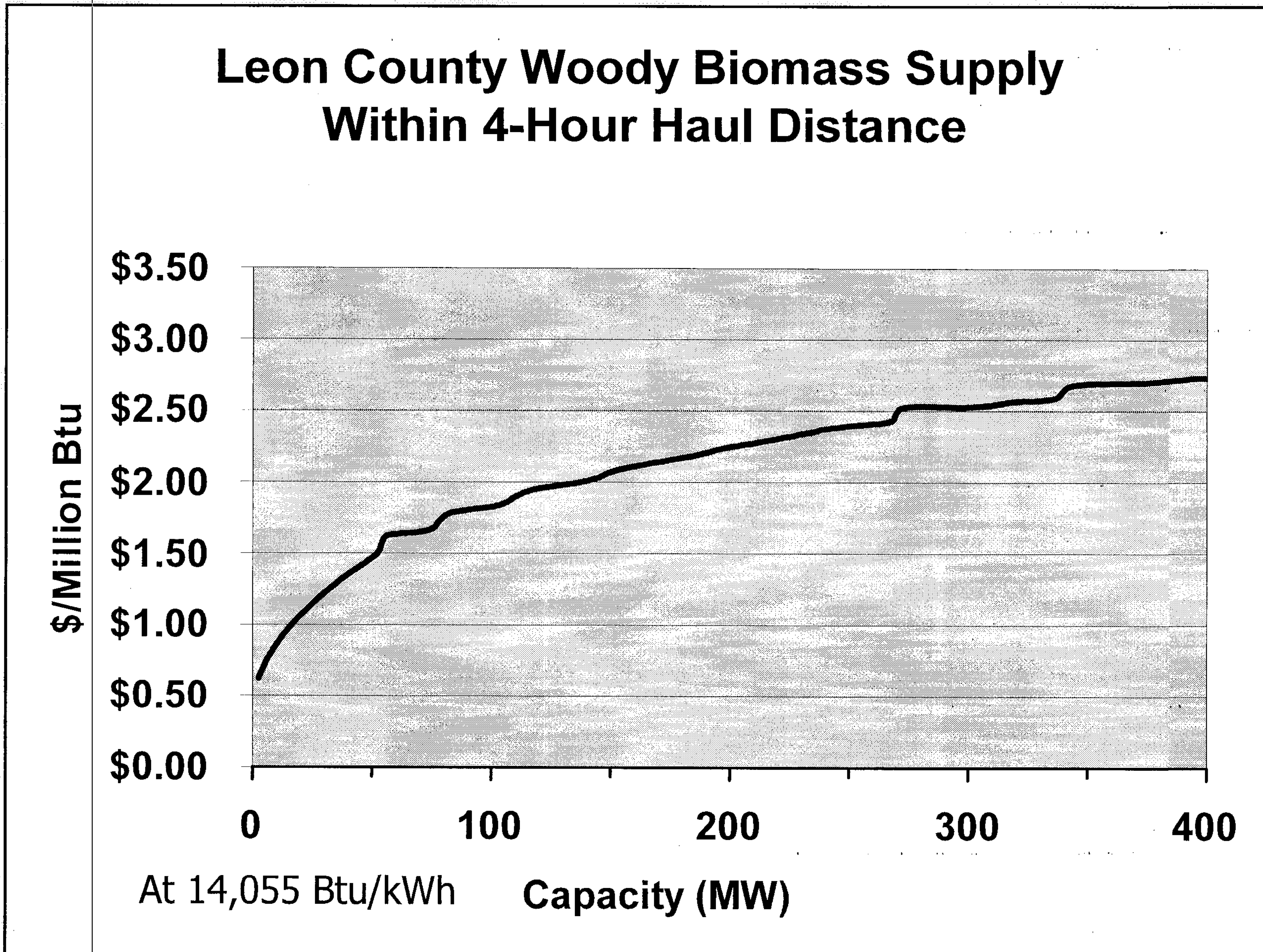
September 27, 2006

Docket No 060635 EU
Tallahassee biomass
Ex. DD4
p. 1 of 9

Sources of Woody-Biomass, 4-Hr Haul Distance

- Urban Wood Waste
- Forestry Residues
- Plantation Stumps
- Pulpwood





Leon County Woody Biomass Supply
Within 4-Hour Haul Distance
$/Million Btu
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$0.00
0
100
200
300
400
At 14,055 Btu/kWh
Capacity (MW)

Fuel Costs per kilowatt hour Biomass* vs Coal**

Biomass for 50 MW	1.7 cents
Biomass for 100 MW	2.0 cents
Coal at $2.50/mmBtu	2.3 cents
Coal at $2.75/mmBtu	2.6 cents
Coal at $3.00/mmBtu	2.8 cents

* Spreader-Stoker Generator, 14,055 Btu/kWh
**Supercritical Pulverized Coal Generator, 9315 Btu/kWh

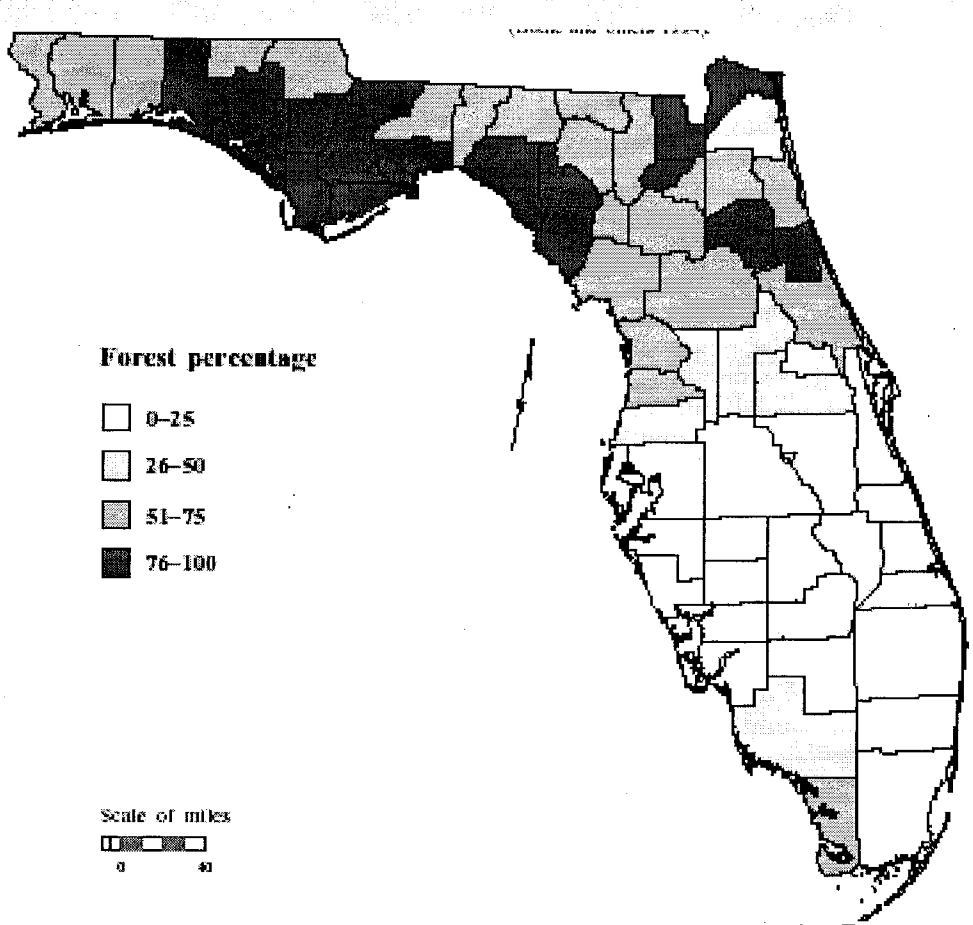
Economic Impact of 40 MW Plant

Capital Construction Cost	$86,750,000
Annual Operating Cost	$13,158,000
Annual Fuel Cost	$8,883,867

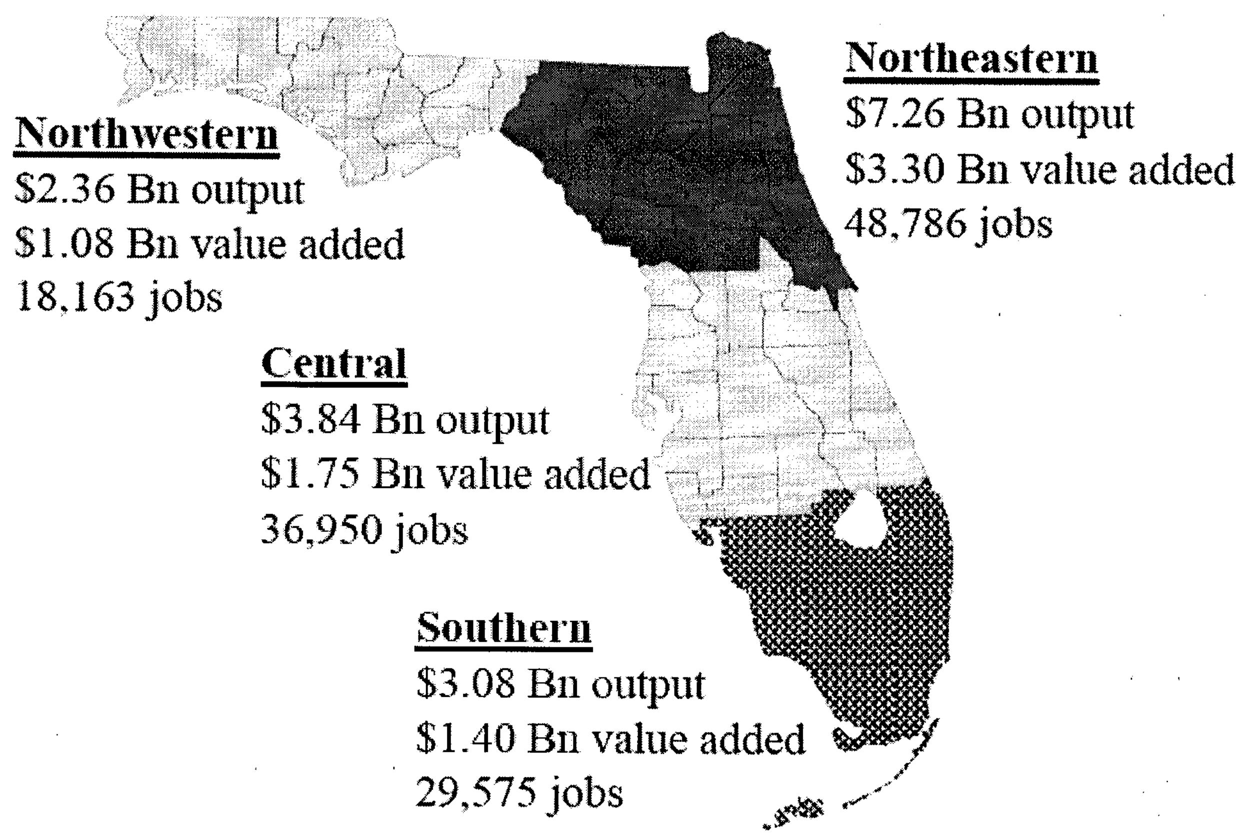
Local Economic Impact

	Output	Jobs	Added Value
Construction	$10,700,000	100	$5,400,000
Annual Operations	$22,000,000	257	$14,000,000

Forest Area Coverage in Florida Counties



Forest Industry Economic Impacts



Team at UF Institute of Food and Agricultural Sciences (IFAS)

- Prof. Martha Monroe, School of Forest Resources and Conservation
- Prof. Douglas Carter, School of Forest Resources and Conservation
- Dr. Mathew Langholtz, School of Forest Resources and Conservation
- Prof. Alan Hodges, Department of Food and Resource Economics

Notes and Caveats:

- Methodology is now undergoing peer review
- These results are based on latest available data, but some of it is from 1995
- Method can be adapted to special circumstances (limits on kind of biomass, distance, etc.)

Docket No 060635-EU
Synapse Report
Ex. PD#5
p. 1 of 64
(ES i - ix)

Synapse
Energy Economics, Inc.

Climate Change and Power:

Carbon Dioxide Emissions Costs and Electricity Resource Planning

Prepared by:
Lucy Johnston, Ezra Hausman,
Anna Sommer, Bruce Biewald,
Tim Woolf, David Schlissel,
Amy Roschelle, and David White

Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
www.synapse-energy.com
617-661-3248

June 8, 2006

Table of Contents

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 60% to 90% of all domestic greenhouse gas reductions are likely to come from the electric sector under a wide range of economy-wide federal policy scenarios.

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,

[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.

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	2005	Cap at 2000 levels	Economy-wide, large emitting sources
Bingaman-Domenici (NCEP)	Greenhouse Gas Intensity Reduction Goals	2004	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.

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.

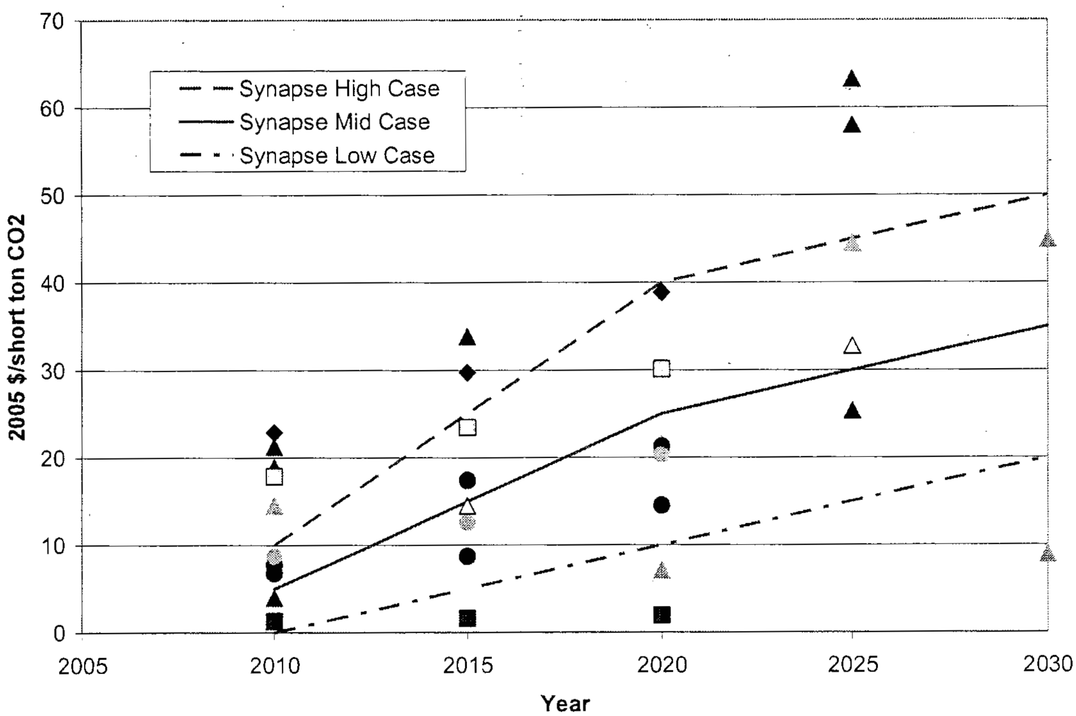


Figure ES-1. Synapse Forecast of Carbon Dioxide Allowance Prices

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

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.[2]

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.[3] 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

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

[3] 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.[4]

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.[5] 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."[6] 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.[7] 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.[8]

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.

[4] Ibid., pages 45-48.

[5] CERES; "Electric Power, Investors, and Climate Change: A Call to Action;" September 2003.

[6] Ibid., p. 6

[7] Innovest Strategic Value Advisors; "Power Switch: Impacts of Climate Change on the Global Power Sector;" WWF International; November 2003

[8] 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.[9] 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.[10] 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

[9] 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.

[10] 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.[11]

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.[12] 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:[13]

---

[11] IPCC, *Climate Change 2001: Synthesis Report*, Fourth Volume of the IPCC Third Assessment Report. IPCC 2001. Question 6.

[12] *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.

[13] 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.[14]

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.[15] Figure 3.1 shows the top twenty carbon dioxide emitters in the world.

[14] Several websites provide summary information on climate change science including www.ipcc.org www.nrdc.org, www.ucsusa.org, and www.climateark.org.

[15] International Energy Agency, "CO_2 from Fuel Combustion – Fact Sheet," 2005

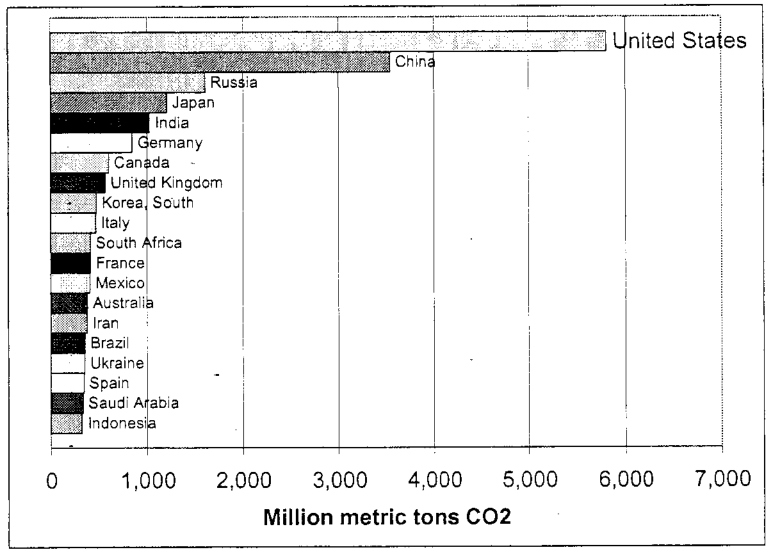


Figure 3.1. Top Worldwide Emitters of Carbon Dioxide in 2003

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.

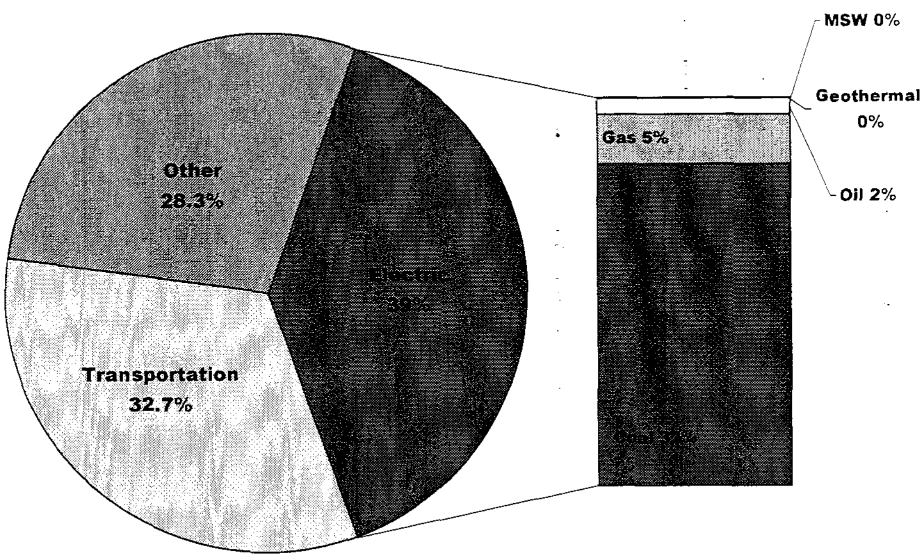


Figure 3.2. US CO_2 Emissions by Sector in 2004

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.[16] 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.[17] 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.[18] 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.

---

[16] EIA, "Emissions of Greenhouse Gases in the United Sates, 2004;" Energy Information Administration; December 2005, xiii

[17] EIA *Emissions of Greenhouse Gases in the United States 2004,* December 2005.

[18] 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.[19] 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.[20] 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."[21] 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.[22] 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.[23] 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

[19] 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/.

[20] 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.

[21] From Article 3 of the United Nations Framework Convention on Climate Change, 1992.

[22] 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

[23] Greenhouse gases covered by the Protocol are CO_2, CH_4, N_2O, HFCs, PFCs and SF_6.

February 2005.[24] 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[25]

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.[26] The leaders

[24] 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.

[25] Background information at: http://unfccc.int/essential_background/kyoto_protocol/items/3145.php

[26] 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.[27] 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.[28] The EU has committed to emission reductions of 20-30% below 1990 levels by 2020, and reduction targets for 2050 are still under discussion.[29]

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.

at: http://www.g8.gov.uk/servlet/Front?pagename=OpenMarket/Xcelerate/ShowPage&c=Page&cid=1094235520309

[27] Council of the European Union, *Information Note – Brussels March 10, 2005.* http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

[28] 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

[29] 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."[30] 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.[31] 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. [32]

[30] The UNFCC was signed by President George H. Bush in 1992 and ratified by the Senate in the same year.

[31] "Bush acknowledges human contribution to global warming; calls for post-Kyoto strategy." Greenwire, July 6, 2005.

[32] 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.[33]

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.

[33] "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	2005	Cap at 2000 levels	Economy-wide, large emitting sources
Bingaman-Domenici (NCEP)	Greenhouse Gas Intensity Reduction Goals	2004	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.[34] 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.[35] 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.[36]

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.[37] 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,

[34] National Commission on Energy Policy, *Ending the Energy Stalemate*, December 2004, pages 19-29.

[35] 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.

[36] 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

[37] 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.[38]

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.

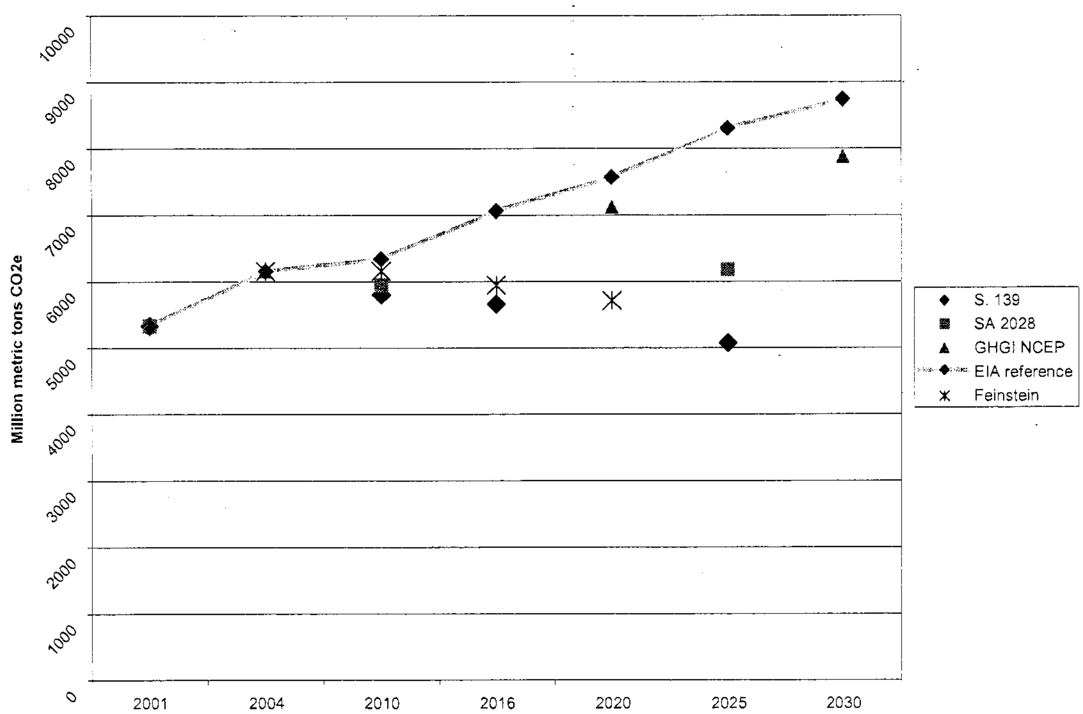


Figure 5.1. Emission Trajectories of Proposed Federal Legislation

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.

[38] Press release, "Udall and Petri introduce legislation to curb global warming," March 29, 2006.

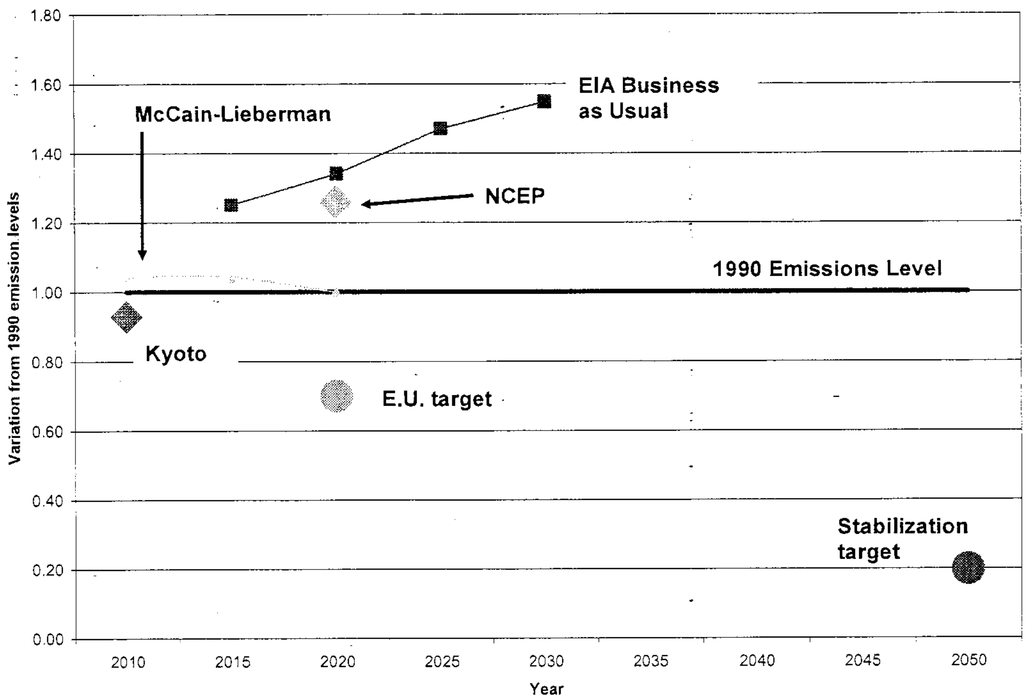


Figure 5.2 Comparison of Emission Reduction Goals

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.[39] 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).[40]

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.[41] 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

[39] 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.

[40] Press release, "Codey Takes Crucial Step to Combat Global Warming," October 18, 2005.

[41] 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.[42] Pennsylvania, the District of Columbia, the Eastern Canadian Provinces, and New Brunswick are official "observers" in the RGGI process.[43]

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.[44]

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.[45] 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.[46]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

[42] Maryland Senate Bill 154 *Healthy Air Act*, signed April 6, 2006.

[43] Information on this effort is available at www.rggi.org

[44] 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.

[45] the US Mayors Climate Protection Agreement, 2005. Information available at http://www.ci.seattle.wa.us/mayor/climate

[46] 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.[47]

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."[48] 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.[49]

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.[50] Similarly, in a 2005 survey of the North American electricity industry, 93% of respondents anticipate increased pressure to take action on global climate change.[51]

---

[47] 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

[48] 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/

[49] 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.

[50] PA Consulting Group, "Environmental Survey 2004" Press release, October 22, 2004.

[51] 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.[52] 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.[53]

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.[54] 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. [55] 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

[52] "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors," CERES press release, February 17, 2005.

[53] "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.

[54] 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.

[55] 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.[56] 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. [57]

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.[58]
- 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.[59]

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.[60]

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

[56] See: http://www.cdproject.net/aboutus.asp

[57] 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.

[58] FT 500 is the Financial Times' ranking of the top 500 companies ranked globally and by sector based on market capital.

[59] CDP press release, September 14, 2005. Information on the Carbon Disclosure Project, including reports, are available at: http://www.cdproject.net/index.asp.

[60] *Greenwire*, February 16, 2005

reduction targets and supporting a national policy to limit greenhouse gas emissions. [61] 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."[62] The President of Duke Energy urges a federal carbon tax, and states that Duke should be a leader on climate change policy.[63] 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.[64] 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

---

[61] Goldman Sachs Environmental Policy Framework, http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

[62] Jacobson, Sanne, Neil Numark and Paloma Sarria, "Greenhouse Gas Emissions: A Changing US Climate," *Public Utilities Fortnightly*, February 2005.

[63] Paul M. Anderson Letter to Shareholders, March 15, 2005.

[64] 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.[65] 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.[66] 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.[67] 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.[68] 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.

---

[65] Lempert, Popper, Resitar and Hart, "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change, October 2002. page

[66] US EPA, *Analysis of Emissions Reduction Options for the Electric Power Industry,* March 1999.

[67] US EPA, *Briefing Report*, March 1999.

[68] 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. [69]

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).[70] 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.[71]

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

[69] "What determines the Price of Carbon," Carbon Market Analyst, *Point Carbon*, October 14, 2004.

[70] These prices are from Evolution Express trade data, http://www.evomarkets.com/, accessed on 3/31/06.

[71] 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.[72]

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.[73] 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.[74] 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).[75] 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."[76] 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.

---

[72] 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

[73] California Public Utilities Commission, Decision 04-12-048, December 16, 2004

[74] California Public Utilities Commission, Decision 05-04-024, April 2005.

[75] Montana Public Service Commission, "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229," August 17, 2004.

[76] 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 economy-wide 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).[77]

In 2003 researchers at the Massachusetts Institute of Technology also analyzed potential costs of the McCain Lieberman legislation.[78] 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).[79] 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

---

[77] 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

[78] 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.

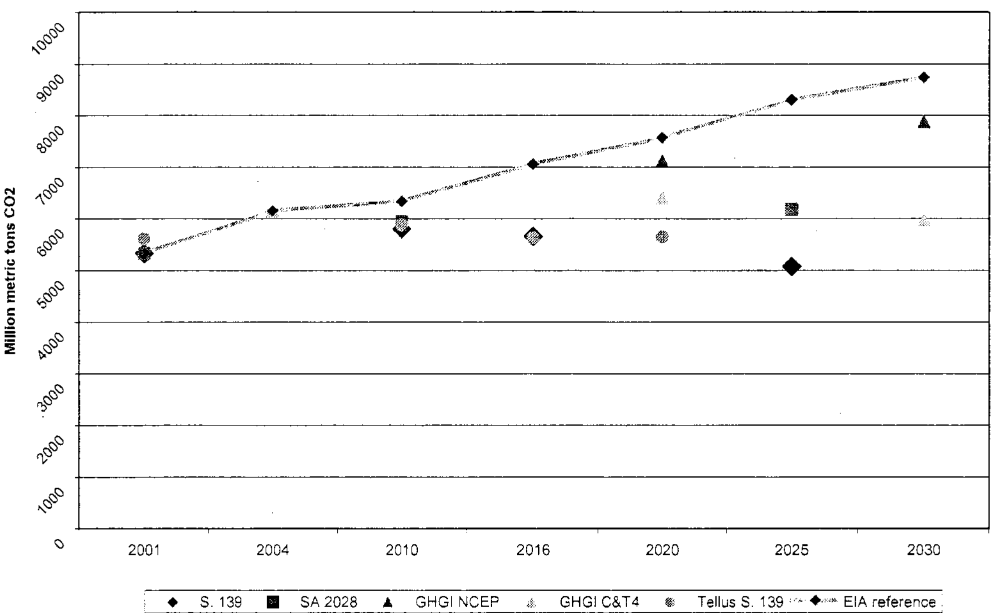
[79] Bailie et al., *Analysis of the Climate Stewardship Act,* July 2003; Bailie and Dougherty, *Analysis of the Climate Stewardship Act Amendment*, Tellus Institute, June, 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

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.[80] 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).[81] EPA also analyzed the power sector proposal from Senator Jeffords (S. 150).[82]

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.



[80] EIA, *Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals,* March 2006. SR/OIAF/2006-01.

[81] 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.

[82] 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.

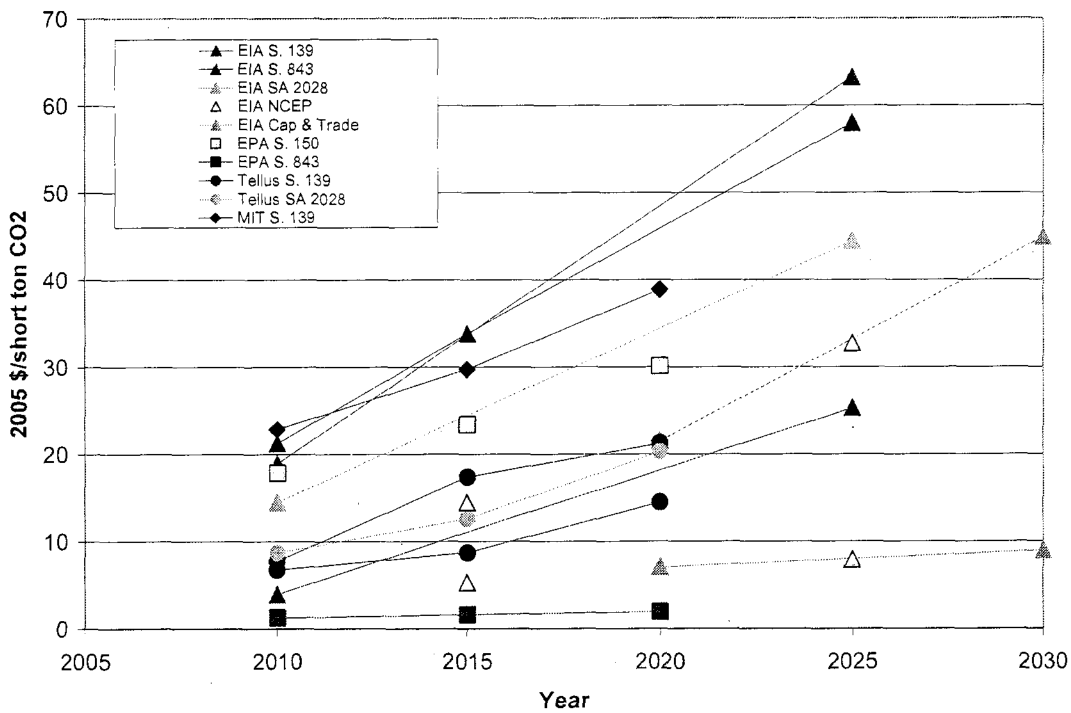


Figure 6.2. Allowance Cost Estimates From Studies of Economy-wide and Electric Sector US Policy Proposals

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.[83] In 1999 EIA performed a very similar study, but looked at phasing in carbon prices beginning in 2000 instead of 2005 as in the

[83] EIA, "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity," October 1998. SR/OIAD/98-03

original study.[84] 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.[85] 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 $US 2004, 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.[86]

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.

[84] EIA, "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol," July 1999. SR/OIAF/99-02.

[85] ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

[86] 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.[87] 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.[88]

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

---

[87] 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

[88] 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.[89] 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."[90] 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

[89] 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.

[90] 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

Assumption	Increases Prices if...	Decreases Prices if...
• **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.

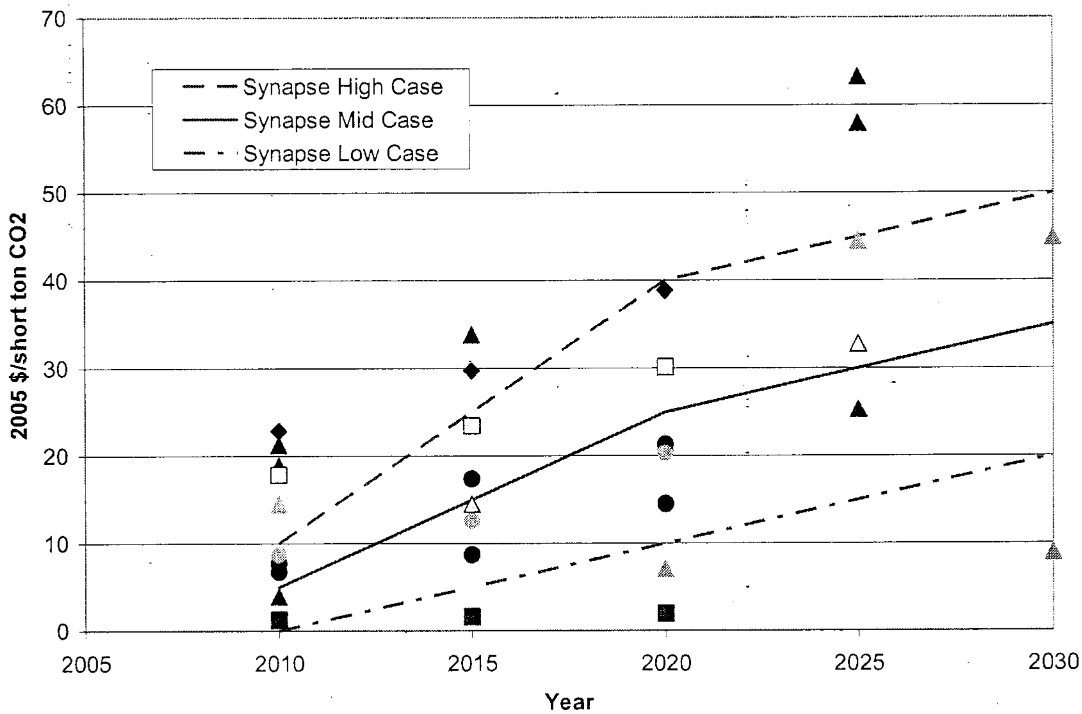


Figure 6.3. Synapse Forecast of Carbon Dioxide Allowance Prices

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 2010-2040
Synapse Low Case	0	10	20	8.5
Synapse Mid Case	5	25	35	19.6
Synapse High Case	10	40	50	30.8

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 updates and expands upon previous versions of Synapse Energy Economics reports on climate change and carbon prices.

This version, dated June 8, 2006, is identical to the version dated May 18, save for a correction to the unit description used in Figure 6.2.

References

Anderson, Paul M. Chairman, Duke Energy. "Letter to Shareholders." March 15, 2005.

Anderson, Paul. 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

Avista Utilities, *Electric Integrated Resource Plan 2005,* August 31, 2005. Available at http://www.avistautilities.com/resources/plans/documents/Avista_2005_IRP_Final.pdf

Bailie, Bernow, Dougherty, and Lazarus. *Analysis of the Climate Stewardship Act.* Tellus Institute, July 2003. Available at: http://www.tellus.org/energy/publications/McCainLieberman2003.pdf

Bailie and Dougherty. *Analysis of the Climate Stewardship Act Amendment.* Tellus Institute. June 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

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. Available at http://www.synapse-energy.com/Downloads/AResponsibleElectricityFuture.pdf

California Public Utilities Commission. Decision 04-12-048. December 16, 2004. Available at http://www.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/42314-07.htm#P761_196099

California Public Utilities Commission. Decision 05-04-024 "Interim Opinion on E3 Avoided Cost Methodology." April 7, 2005. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45284.htm

Carbon Disclosure Project. "$21 Trillion Investor Coalition Spurs Greater Awareness of Climate Change Among US Corporations US Corporates Wake Up to Climate Change Risks and Opportunities." Press release. September 14, 2005. http://www.cdproject.net/viewrelease.asp?id=2

Carbon Market Analyst. "What determines the Price of Carbon." *Point Carbon.* October 14, 2004.

Center for Clean Air Policy. *Connecticut Climate Change Stakeholder Dialogue: Recommendations to the Governors' Steering Committee.* January 2004. Available at http://www.ctclimatechange.com/pdf/01_history_ed.pdf

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

CERES. "Four Electric Power Companies in Midwest Agree to Disclose Climate Risk." Press release. February 21, 2006.

CERES. "US Companies Face Record Number of Global Warming Shareholder Resolutions on Wider Range of Business Sectors." Press release. February 17, 2005. Available at http://ceres.org/newsroom/press/gwsc_pr_021805.htm

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

Codey, Acting Governor Richard. "Codey Takes Crucial Step to Combat Global Warming." Press release. October 18, 2005. http://www.nj.gov/cgi-bin/governor/njnewsline/view_article.pl?id=2779

Cogan, Douglas G. citing Frank Dixon and Martin Whittaker. "Valuing corporate environmental performance: Innovest's evaluation of the electric utilities industry," *Corporate Environmental Strategy*, Vol. 6, No. 4. New York, 1999.

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. Available at http://www.incr.com/investor_guide/

Congressional Budget Office, *Uncertainty in Analyzing Climate Change: Policy Implications*, January 2005

Congressional Budget Office, Economic and Budget Issue Brief, *Limiting Carbon Dioxide Emissions: Prices Versus Caps*, March 15, 2005.

Congressional Budget Office, *Shifting the Cost Burden of a Carbon Cap-and-TradeProgram,* July 2003

Council of the European Union, Information Note – Brussels March 10, 2005. http://ue.eu.int/uedocs/cmsUpload/st07242.en05.pdf

Domenici, Senator Pete V. and Senator Jeff Bingaman. "Design Elements of a Mandatory Market-based Greenhouse Gas Regulatory System," Senate Committee on Energy and Natural Resources, issued February 2, 2006. http://members.4cleanair.org/rc_files/3243/Domenici&Bingamanwhitepaper2-2-06.pdf

EIA. "Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity." October 1998. SR/OIAF/98-03. Available at: http://www.eia.doe.gov/oiaf/kyoto/pdf/sroiaf9803.pdf

EIA. "Analysis of the Impacts of an Early Start for Compliance with the Kyoto Protocol." July 1999. SR/OIAF/99-02. http://www.eia.doe.gov/oiaf/kyoto3/kyoto3rpt.html

EIA. *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide.* December 2000. SR/OIAF/2001-03. Available at http://www.eia.doe.gov/oiaf/servicerpt/epp/

EIA, Analysis of S. 139, the Climate Stewardship Act of 2003, EIA June 2003, SR/OIAF/2003-02. Available at http://tonto.eia.doe.gov/FTPROOT/service/sroiaf(2003)02.pdf

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. Available at http://www.eia.doe.gov/oiaf/servicerpt/ccs/pdf/sroiaf(2003)03.pdf

Energy Information Administration, Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003, EIA May 2004, SR/OIAF/2004-06. Available at http://www.eia.doe.gov/oiaf/analysispaper/sacsa/pdf/s139amend_analysis.pdf

EIA Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels. 1980-2002 (posted June 9, 2004). Available at http://www.eia.doe.gov/emeu/international/environm.html#IntlCarbon

EIA. "Emissions of Greenhouse Gases in the United States, 2004." December 2005. DOE/EIA-0573(2004). http://www.eia.doe.gov/oiaf/1605/ggrpt/index.html

EIA. "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals." March 2006. SR/OIAF/2006-01. http://www.eia.doe.gov/oiaf/servicerpt/agg/pdf/sroiaf(2006)01.pdf

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

Feinstein, Senator Dianne. "Senator Feinstein Outlines New Legislation to Curb Global Warming, Keep Economy Strong." *News from Senator Feinstein*. March 20, 2006. http://feinstein.senate.gov/06releases/r-global-warm320.pdf

Fischer, Carolyn and Richard D. Morgenstern. "Carbon Abatement Costs: Why the Wide Range of Estimates?" Resources for the Future. September, 2003. Available at http://www.rff.org/Documents/RFF-DP-03-42.pdf

Fontaine, Peter. "Greenhouse-Gas Emissions: A New World Order." *Public Utilities Fortnightly*. February 2005.

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 at: http://www.g8.gov.uk/servlet/Front?pagename=OpenMarket/Xcelerate/ShowPage&c=Page&cid=1094235520309

GF Energy. "GF Energy 2005 Electricity Outlook." January 2005. http://www.gfenergy.com/download.html

Goldman Sachs Environmental Policy Framework, November 2005. http://www.gs.com/our_firm/our_culture/corporate_citizenship/environmental_policy_framework/docs/EnvironmentalPolicyFramework.pdf

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.

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. Available at http://www.nrdc.org/air/pollution/benchmarking/default.asp

Greenwire. February 16, 2005. Available at http://www.eenews.net/gw/

ICF Consulting presentation of "RGGI Electricity Sector Modeling Results," September 21, 2005. Results of the ICF analysis are available at www.rggi.org

Idaho Power Company. *2004 Integrated Resource Plan Draft*. July 2004. Available at http://www.idahopower.com/energycenter/2004IRPFinal.htm

Innovest Strategic Value Advisors. *Carbon Disclosure Project 2005,* third report of the Carbon Disclosure Project. Innovest Strategic Value Advisors and the Carbon Disclosure Project. September 2005. Available at http://www.cdproject.net/

Innovest Strategic Value Advisors. "Power Switch: Impacts of Climate Change on the Global Power Sector." World Wildlife Fund International. November 2003. Available at http://www.innovestgroup.com/pdfs/2003-11-PowerSwitch.pdf

Innovest Strategic Value Advisors. "Value at Risk: Climate Change and the Future of Governance." The Coalition for Environmentally Responsible Economies. June 2003. Available at http://www.ceres.org/pub/docs/Ceres_value_at_risk_0418.pdf

Intergovernmental Panel on Climate Change. "16 Years of Scientific Assessment in Support of the Climate Convention." December 2004. Available at http://www.ipcc.ch/about/anniversarybrochure.pdf

Intergovernmental Panel on Climate Change. "Introduction to the Intergovernmental Panel on Climate Change." 2003 edition. Available at www.ipcc.ch/about/beng.pdf.

International Association for Energy Economics. "The Costs of the Kyoto Protocol: A Multi-Model Evaluation." *The Energy Journal*. 1999.

International Energy Agency. "CO_2 from Fuel Combustion – Fact Sheet." 2005. Available at http://www.iea.org/journalists/docs/CO2.pdf.

Investor Network on Climate Risk. "A New Call for Action: Managing Climate Risk and Capturing the Opportunities." 2005 Institutional Investor Summit. May 10, 2005. http://www.ceres.org/pub/docs/Ceres_INCR_05_call_for_action.pdf

Investor Network on Climate Risk. "Institutional Investor Summit on Climate Risk Final Report." Available at http://www.incr.com/summit_final_report.pdf.

IPCC. *Third Assessment Report: Climate Change 2001*. Intergovernmental Panel on Climate Change 2001. http://www.ipcc.ch/

Jacobson, Sanne, Neil Numark and Paloma Sarria. "Greenhouse – Gas Emissions: A Changing US Climate." *Public Utilities Fortnightly*. February 2005.

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

Lempert, Popper, Resitar and Hart. "Capital Cycles and the Timing of Climate Change Policy." Pew Center on Global Climate Change. October 2002. Available at http://www.pewclimate.org/docUploads/capital%5Fcycles%2Epdf

Maryland Senate Bill 154 Healthy Air Act, signed April 6, 2006

Moler, Elizabeth, 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/

Montana Public Service Commission. "Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229." August 17, 2004.

National Commission on Energy Policy. *Ending the Energy Stalemate*. December 2004. Available at http://www.energycommission.org/

Nordhaus, William and Boyer, Joseph. "Requiem for Kyoto: An Economic Analysis." *The Energy Journal*. 1999.

Northwestern Energy, *2005 Electric Default Supply Resource Procurement Plan,* December 20, 2005. http://www.montanaenergyforum.com/plan.html.

Northwest Power and Conservation Council, *The Fifth Northwest Electric Power and Conservation Plan*, May 2005. http://www.nwcouncil.org/energy/powerplan/plan/Default.htm

PA Consulting Group. "Environmental Survey 2004." Press release, October 22, 2004. http://www.paconsulting.com/news/press_release/2004/pr_carbon_dioxide_regulations.htm

PacifiCorp. *Integrated Resource Plan 2003*. Available at http://www.pacificorp.com/File/File25682.pdf

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

Pershing, Jonathan, *Comments in Response to Bingaman-Domenici Climate Change White Paper*, World Resources Institute, March 13, 2006.

Regional Greenhouse Gas Initiative. Information, including Memorandum of Understanding, proposed Model Rule, comments on State Working Group proposals, and all meeting presentations, available at: www.rggi.org

Rendell, Governor Edward. "Governor Rendell Launches Initiative to Support Manufacturers, Continue Job Growth; Bold Homegrown Solution Maintains PA Energy Leadership." Press release. November 28, 2005. http://www.state.pa.us/papower/cwp/view.asp?A=11&Q=447926

Rowe, John W., *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

TIME/ABC News/Stanford University Poll. "Global Warming - Seeing the problem, not the solution." *TIME.* April 3, 2006 Vol. 167 No. 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

US Conference of Mayors, The. "US Mayors Climate Protection Agreement." 2005. http://www.usmayors.org/uscm/resolutions/73rd_conference/env_04.asp. Information on the Mayors Climate Protection Agreement also available at: http://www.ci.seattle.wa.us/mayor/climate/

Udall, Rep. Tom. "Udall and Petri introduce legislation to curb global warming." Press release. March 29, 2006 http://www.tomudall.house.gov/issues2.cfm?id=11699

United Nations Framework Convention on Climate Change, 1992. Available at http://unfccc.int/resource/docs/convkp/conveng.pdf. The UNFCC has comprehensive information on the UNFCC, and the Kyoto Protocol on its website at http://unfccc.int/

UNFCCC, *Caring for Climate: A guide to the Climate Change Convention and the Kyoto Protocol (revised 2005 edition)*; 2005. Issued by the Climate Change Secretariat (UNFCCC) Bonn, Germany.

US Environmental Protection Agency. "Analysis of Emissions Reduction Options for the Electric Power Industry." March 1999.

US Environmental Protection Agency, *Multi-pollutant Legislative Analysis: The Clean Power Act (Jeffords, S. 150 in the 109th).* US EPA Office of Air and Radiation, October 2005. Available at: http://www.epa.gov/airmarkets/mp/

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. Available at: http://www.epa.gov/airmarkets/mp/

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

Wiser, Ryan and Mark Bolinger. *An Overview of Alternative Fossil Fuel Price and Carbon Regulation Scenarios*. Lawrence Berkeley National Laboratory. October 2004. LBNL-56403. Available at http://eetd.lbl.gov/ea/ems/reports/56403.pdf

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

Xcel-PSCCo, *Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E*, December 3, 2004. http://www.xcelenergy.com/docs/corpcomm/SettlementAgreementFinalDraftclean20041203.pdf

Docket No 000055 EL
CO2 Costs
Ex DD6
p. 1 of 9

Proceedings of 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada, September 5-9, 2004

COMPARATIVE ASSESSMENTS OF FOSSIL FUEL POWER PLANTS WITH CO_2 CAPTURE AND STORAGE

Edward S. Rubin,[1] Anand B. Rao and Chao Chen
Department of Engineering and Public Policy
Carnegie Mellon University
Pittsburgh, PA 15213 USA

Abstract

Studies of CO_2 capture and storage (CCS) costs necessarily employ a host of technical and economic assumptions regarding the particular technology or system of interest, including details regarding the capture technology design, the power plant or gas stream treated, and the methods of CO_2 transport and storage. Because the specific assumptions employed can dramatically affect the results of an analysis, published studies are often of limited value to researchers, analysts and industry personnel seeking results for alternative assumptions or plant characteristics. In the present paper, we use a generalized modeling tool to estimate and compare the emissions, efficiency, resource requirements and costs of PC, IGCC and NGCC power plants on a systematic basis. This plant-level analysis explores a broader range of key assumptions than found in recent studies we reviewed. In particular, the effects on cost comparisons of higher natural gas prices and differential plant utilization rates are highlighted, along with implications of financing and operating assumptions for IGCC plants. The impacts of CCS energy requirements on plant-level resource requirements and multi-media emissions also are quantified. While some CCS technologies offer ancillary benefits via the co-capture of certain criteria air pollutants, the increases in specific fuel consumption, reagent use, solid wastes and other air pollutants associated with current CCS systems are found to be significant. To properly characterize such impacts, an alternative definition of the "energy penalty" is proposed in lieu of the prevailing use of this term.

INTRODUCTION

CO_2 capture and storage (CCS) is receiving considerable attention as a greenhouse gas (GHG) mitigation option since it has the potential to allow continued use of fossil fuels with little or no emissions of CO_2 to the atmosphere. This could allow a smoother and less costly transition to a sustainable, low-carbon energy future over the next century [1]. Although technology currently exists to capture the CO_2 generated by large-scale industrial processes, the reliability and safety of a large-scale CO_2 sequestration program remain to be demonstrated to the satisfaction of policy-makers. Even assuming its eventual public acceptance, the cost of CCS technology could pose another barrier to its widespread use as a GHG control strategy. A number of recent studies have estimated CCS costs based on technologies that are either currently commercial or under development. For the most part, these studies have focused on coal-based power plants, which are a major source of CO_2 emissions [2]. While a few of these studies also have noted the ancillary benefits of CCS such as improved capture of criteria air pollutants (like sulfur dioxide, SO_2), a more complete picture of the environmental and resource implications of CO_2 capture is largely absent in the current literature.

Scope and Objectives of This Paper

Our principal objectives in this paper are to: (1) summarize and compare the results of recent studies of the current cost of fossil fuel power systems with and without CO_2 capture, including natural gas combined cycle (NGCC) plants, pulverized coal combustion (PC) plants, and coal-based integrated gasification combined cycle (IGCC) plants; (2) explore a broader range of key assumptions that influence these cost comparisons; and (3) quantify the implications of CCS energy requirements on plant-level resource requirements and multi-media emissions. The latter topic has been largely ignored in past studies of CCS options, but its consequences are potentially significant, as the analysis below will demonstrate. We conclude by discussing the potential for advanced technologies to reduce the costs and ancillary impacts found for current CCS and power generation technologies.

[1] Corresponding author: Email: rubin@cmu.edu, Tel: (412) 268-5897, Fax: (412) 268-1089

REVIEW OF RECENT COST STUDIES

Table 1 summarizes the range of costs for new plants using current commercial power generation and CO_2 capture technologies, as reported in recent studies we reviewed [3-13]. These costs include CO_2 compression, but not CO_2 transport and storage costs, which are not included in most recent studies.

Table 1. Summary of reported CO_2 emissions and costs for a new electric power plant with and without CO_2 capture based on current technology (excluding CO_2 transport and storage costs)*

Cost and Performance Measures	PC Plant		IGCC Plant		NGCC Plant	
	Range low-high	*Rep. value*	**Range low-high**	*Rep. value*	**Range low-high**	*Rep. value*
Emission rate w/o capture (kg CO_2/MWh)	722-941	795	682-846	757	344-364	358
Emission rate with capture (kg CO_2/MWh)	59-148	116	70-152	113	40-63	50
Percent CO_2 reduction per kWh (%)	80-93	85	81-91	85	83-88	87
Capital cost w/o capture ($/kW)	1100-1490	1260	1170-1590	1380	447-690	560
Capital cost with capture ($/kW)	1940-2580	2210	1410-2380	1880	820-2020	1190
Percent increase in capital cost (%)	67-87	77	19-66	36	37-190	110
COE w/o capture ($/MWh)	37-52	45	41-58	48	22-35	31
COE with capture ($/MWh)	64-87	77	54-81	65	32-58	46
Percent increase in COE w/capture (%)	61-84	73	20-55	35	32-69	48
Cost of CO_2 avoided ($/t CO_2)	42-55	47	13-37	26	35-74	47
Cost of CO_2 captured ($/t CO_2)	29-44	34	11-32	22	28-57	41
Energy penalty for capture (% MW_{ref})	22-29	27	12-20	16	14-16	15

*Definitions: MW_{ref}= reference plant net output; COE=cost of electricity; Rep. value=representative value; PC=pulverized coal; NGCC=natural gas combined cycle; IGCC=integrated gasification combined cycle. Notes: Ranges and representative values are based on recent studies reviewed (see text). Capture costs include compression. Cost of CO_2 avoided is based on the given plant type wit and without capture, but excluding transport and storage. NGCC cases based on natural gas prices averaging US$3/GJ. Coal prices average $1.3/GJ. Plant sizes range from 400-1200 MW (typical=550 MW).

Table 1 reveals substantial variability in both the absolute and relative costs of power generation and CO_2 capture for the three fossil fuel systems shown. This variability arises mainly from different assumptions about key factors that affect the projected cost of electricity (COE) for a particular system (such as fuel properties, fuel cost, plant size, plant efficiency, plant capacity factor, and plant financing), as well as assumptions about the performance and operation of the CO_2 capture unit and other environmental control systems. The contribution of different factors to overall cost is illustrated by Rao and Rubin [11] for the case of a PC plant with CO_2 capture. Although Table 1 reflects a range of assumptions and perspectives for each of the three power systems, the general conclusion that emerges from recent studies is that the total cost of electricity generation tends to be lowest for NGCC plants, with or without CO_2 capture. For coal-based plants, PC units tend to have lower capital costs and COE without capture, while IGCC plants tend to be less expensive when current CO_2 capture systems are added. Because costs depend on many factors, the generalizations above do not apply in all cases. To date, however, only a few studies have performed systematic analyses of both coal-based and NGCC plants with CO_2 capture. As elaborated below, recent studies of NGCC systems in particular have used fuel price and other assumptions that today appear questionable. Thus, we attempt here to explore a broader range of conditions that affect comparative costs.

ANALYTICAL METHOD FOR CURRENT ASSESSMENTS

To account for the many factors that affect CCS costs and emissions at electric power plants, we use the Integrated Environmental Control Model (IECM) to systematically evaluate the three types of fossil fuel power systems noted above. The IECM is a publicly available modeling tool developed by Carnegie Mellon University for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) [14]. It has been used previously to characterize the costs of PC plants using an amine-based CO_2 capture system [11]. The IECM has now been expanded to include NGCC and IGCC plants with and without CO_2 capture and storage, based on current commercial technologies. Additional models of advanced technologies are currently under development.

As with the PC plant, the new NGCC and IGCC models employ fundamental mass and energy balances, together with empirical data where needed, to quantify overall plant performance, resource requirements and emissions. Plant and process performance model are linked to a companion set of engineering economic models that calculate the capital cost and annual operating and maintenance (O&M) costs of individual plant components, and the total cost of electricity (COE) for the overall plant. Detailed documentation describing each of the power systems and component models is available elsewhere [14-17]. In this paper we focus on some of the major factors that affect the relative costs and environmental impacts of CCS for the three power systems of interest.

BASELINE COMPARISONS

We first compare systems based on assumptions similar to those found in other recent studies, except that for the NGCC plant we use a higher natural gas price (of approximately \$4/GJ). Table 2 summarizes other key assumptions for this "baseline" analysis. In each case, the "reference" plant is a 500 MW baseload facility without CO_2 capture, while the "capture" plant refers to a similar facility with CCS. For the PC unit, the gross plant size with capture is increased to maintain a net output of approximately 500 MW (in contrast to most studies, which assume the reference plant is derated). The NGCC and IGCC plants retain the same equipment sizes as the reference plant since gas turbines are available only in certain sizes. Both the PC and NGCC employ an amine-based system for CO_2 capture, while the IGCC plant adds a water gas shift reactor and a Selexol unit to capture CO_2. All three systems include pipeline transport and geological storage of high-pressure (liquefied) CO_2. The nominal case is injection of CO_2 into a deep underground aquifer, while an alternative case assumes CO_2 is first used for enhanced oil recovery (EOR), thus generating a cost credit for the CCS system. Some of the key cost assumptions are shown in Table 2. Although the IECM has a probabilistic capability for modeling uncertainty or variability, in this paper we use conventional deterministic analysis for simplicity and ease of comparison with other studies.

Table 2. Key assumptions for the baseline analysis

Parameter	PC[a]		IGCC[b]		NGCC[c]	
	Ref	Capture	Ref	Capture	Ref	Capture
Fuel used	U.S.Appalachian bituminous coal [d]				Natural gas [e]	
Gross plant size (MW)	575	710	606	596	517	517
Net plant output (MW)	524	492	527	492	507	432
Net plant efficiency, HHV (%)	39.3	29.9	37.5	32.4	50.2	42.8
Capacity factor (%)	75	75	75	75	75	75
Fixed charge factor (%)	14.8	14.8	14.8	14.8	14.8	14.8
Fuel price (\$/GJ, HHV)	1.2	1.2	1.2	1.2	4.0	4.0
CO_2 capture system		Amine		Shift+Selexol		Amine
CO_2 capture efficiency (%)		90		90		90
CO_2 transport cost (\$/tonne CO_2) [f]		3.2		3.2		3.2
Geologic storage cost (\$/tonne CO_2)		5.0		5.0		5.0
EOR storage credit (\$/tonne CO_2)		10.0		10.0		10.0

[a] Supercritical boiler unit; environmental controls include SCR, ESP and FGD systems, followed by MEA system for CO_2 capture; SO_2 removal efficiency is 98% for reference plant and 99% for capture plant. [b] Based on Texaco quench gasifier (2 + 1 spare), 2 GE 7FA gas turbine, 3-pressure reheat HRSG. Sulfur removal efficiency is 98% via hydrolyzer + Selexol system; Sulfur recovery via Claus plant and Beavon-Stretford tailgas unit. [c] NGCC plant uses two GE 7FA gas turbines and 3-pressure reheat HRSG. [d] As-fired properties are: 2.1%S, 7.2% ash, 5.1% moisture and 30.8 MJ/kg HHV. [e] HHV = 53.9 MJ/kg. [f] Based on pipeline transport distance of 161 km (100 miles); CO_2 stream compressed to 13.7 MPa (2000 psig) with no booster compressors.

Table 3 summarizes the major results of this analysis. The two coal-based reference plants have similar CO_2 emission rates, while the reference NGCC plant emits 55% less CO_2 per MWh. With capture, all three plants remove 90 percent of the flue gas (or fuel gas) CO_2, but emissions rates per MWh are reduced by 87 to 88 percent because of the CCS energy penalties. Without CO_2 capture, the NGCC plant has the lowest levelized cost of electricity at \$43.1/MWh, while the IGCC plant is highest at \$48.3/MWh. With CCS, the gas-fired plant is again the lowest-cost system, but now the IGCC plant has a lower COE than the PC unit. Based on the assumptions outlined in Table 2, the cost of CO_2 transport and storage accounts for 4 to 10 percent of the total COE for these cases.

Table 3. Results for the baseline cases using the IECM

Parameter	Units	PC		IGCC		NGCC	
		Ref	Capture	Ref	Capture	Ref	Capture
CO_2 emission rate	kg/MWh	811	107	817	97	367	43
CO_2 captured	kg/MWh		959		850		387
Total capital requirement	\$/kW	1205	1936	1311	1748	554	909
COE [a] (capture only)	\$/MWh		74.1		62.6		58.9
Cost of electricity (total)	\$/MWh	46.1	82.1	48.3	69.6	43.1	62.1
Cost of CO_2 avoided [b]	\$/tCO2		51.2		29.5		58.7
CCS energy penalty	(out/in) %		23.9		13.8		14.7
	(in/out) %		31.4		16.0		17.2
Assuming EOR credit							
Cost of electricity [a]	\$/MWh	46.1	67.6	48.3	56.7	43.1	56.2
Cost of CO_2 avoided [b]	\$/tCO2		30.5		11.6		40.5

[a] Levelized cost of electricity in constant 2001US\$, excluding cost of CO_2 transport and storage.
[b] All values are relative to the reference plant for the same system.

The case study results in Table 3 are consistent with those of other recent studies (Table 1), although the higher gas price used here makes NGCC more costly than in most previous studies. Note, too, that the exclusion of transport and storage costs (as in many cost studies) can affect the comparative ranking of different systems. This is seen in Table 3 for the case of EOR storage, where the IGCC plant becomes the lowest-cost system because the greater amount of CO_2 captured generates larger credits relative to NGCC. Finally, Table 3 shows that the cost of CO_2 avoided (\$/tonne CO_2) is highest for the NGCC plant and lowest for the IGCC plant in both scenarios. This reflects differences in both the COE and quantity of CO_2 captured for each system. Note that the plant type with the lowest avoidance cost is not necessarily the one with the lowest COE.[2]

EFFECTS OF GAS PRICE AND PLANT DISPATCH

Two assumptions that are especially important in cost comparisons involving NGCC plants are the natural gas cost and the plant utilization factor. Recent studies of NGCC plants have in most cases assumed natural gas prices of approximately \$2-3/GJ over the life of the plant, reflecting the prevailing prices and outlook of the late 1980s and early 1990s in many parts of the world. Consistent with these low prices was the assumption of a high annual load factor (capacity factor) for NGCC units, typically 80 to 90 percent for the studies reflected in Table 1.

In the U.S., the low COE estimated on this basis led to significant investments in simple and combined cycle gas plants over the past decade. However, where coal-fired plants are also available, much of the new gas-fired capacity today goes unutilized. As gas prices have more than doubled over the past five years, average utilization rates for gas turbine-based plants in the U.S. have fallen to as low as 30 percent (see Figure 1). These low capacity factors reflect the fact that power plant dispatch is based on the variable operating cost (VOC) of a unit, not on its total cost of generation (including capital costs). Thus, as natural gas prices have increased, NGCC plants have been utilized less extensively where coal plants, having lower VOC, were also available. This coupling between fuel price and plant capacity factor is typically ignored in conventional plant-level cost analyses. A rigorous treatment requires that plant utilization factors be evaluated in the context of a network of generating plants meeting a specified (time-dependent) electricity demand. This type of analysis requires a power plant dispatch model together with models and assumptions regarding power demand, generation mix, transmission constraints, fuel supplies, capacity additions over time, and other constraints (such as a limit or tax on carbon or air pollutant emissions). Recent work by Johnson and Keith [18] illustrates this approach, which results in different utilization rates for different plant types, depending on the carbon constraint and other factors.

[2] For a single facility, the cost of CO_2 avoided is based on the same plant type with and without CCS, and is defined as: $[(COE)_{ccs} - (COE)_{ref}] / [(CO_2/kWh)_{ref} - (CO_2/kWh)_{ccs}]$. An avoidance cost also can be calculated for any other combination of assumed reference plant and capture plant (e.g., an NGCC reference plant compared to a PC capture plant), or any aggregation of plants with and without a carbon constraint. These cases typically reflect assumptions about what plant types would be built in a particular situation. The resulting cost per tonne values in such cases may differ significantly from those defined here. To help avoid misunderstanding or confusion about the meaning of CO_2 avoidance cost, we use that term sparingly in this paper, preferring instead to emphasize the impact of CCS on the cost of electricity production for a given plant type. From these data, a cost of CO_2 avoided can be calculated for any desired combination of plant types and operating assumptions.

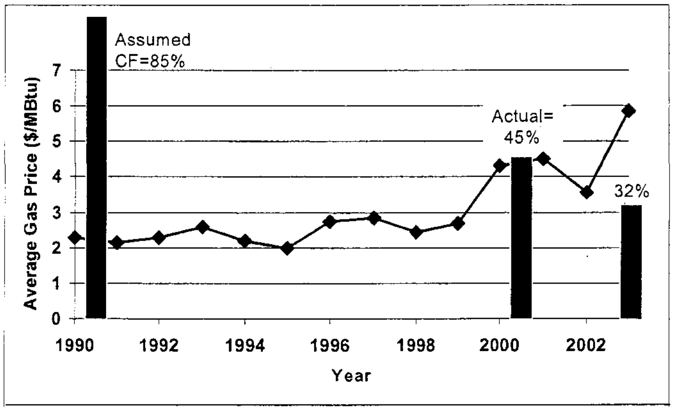


Figure 1. Recent trend in average price of natural gas for U.S. electric utilities. Vertical bars show typical capacity factor assumption for NGCC CCS cost analyses and recent actual values for U.S. plants. [19, 20]

To explore comparative CCS costs in the absence of a particular regional dispatch scenario, we use the differential VOC data in Table 4 to argue qualitatively that the common assumption of a constant (baseload) capacity factor is not likely to be realistic when comparing CO_2 capture costs for NGCC and coal-based plants. Rather, the data in Table 4 suggest that for the reference case with no CO_2 capture (and no carbon constraint), PC and IGCC plants (if built) would have similar utilization rates (as previously assumed), but that NGCC units would have increasingly lower capacity factors as gas prices increased. Based on Figure 1, this scenario assumes a 50% capacity factor for the NGCC reference plant. For the capture plants, IGCC units, having the lowest VOC, would be utilized more than PC plants, while NGCC capture plants, having the highest VOC, would be utilized least.[3] For illustrative purposes, we show results for capacity factors of 85%, 75% and 50% for the IGCC, PC and NGCC plants, respectively. The resulting COEs are shown in Figure 2. Compared to the earlier (Table 3) results based on equal capacity factors for all three plants, the qualitative difference is that the IGCC plant now emerges as the least-cost option rather than NGCC. For the PC plant, the cost of CO_2 capture alone is comparable to the NGCC system, but the overall COE is higher because of the added costs of CO_2 transport and storage. However, if the CO_2 were used for EOR, the PC plant with capture becomes less expensive than NGCC owing to credits from CO_2 sales.

Table 4. Differences in total variable operating cost (VOC) relative to the PC plant* ($/MWh)

Plant	Fuel Price	Reference Plant	Capture Plant
PC	$1.2/GJ	(Base case – ref)	(Base case – ccs)
IGCC	$1.2/GJ	~0	-9
NGCC	$2.2/GJ	+3	-7
NGCC	$4.0/GJ	+16	+8
NGCC	$5.8/GJ	+29	+24

*VOC for the PC plants are $13.1/MWh for the reference plant and $30.0/MWh for the capture plant. VOC includes cost of fuel, chemicals, utilities, waste disposal and byproduct credits. Values for the capture plant include the costs of CO_2 transport and storage.

EFFECTS OF IGCC FINANCING AND OPERATION

Consistent with other studies, the analysis above suggests that IGCC plants could be an attractive option for electric power generation if CCS technology were required. Today, however, IGCC plants are still in the early stages of commercialization and are generally more expensive than conventional PC plants. Because of the limited commercial experience and lack of demonstrated reliability under utility operating conditions, IGCC technology also is generally perceived as riskier by the financial community and by many utility companies. This calls into

[3] A sufficiently high carbon tax would change this result. For the plants shown here, a tax on CO_2 emissions of $400/tonne CO_2 ($1730/tonne C) would be required to equalize the VOC for the IGCC and NGCC capture plants at a natural gas price of $4.50/mscf. Such values far exceed those typically considered in the literature on power plant GHG controls.

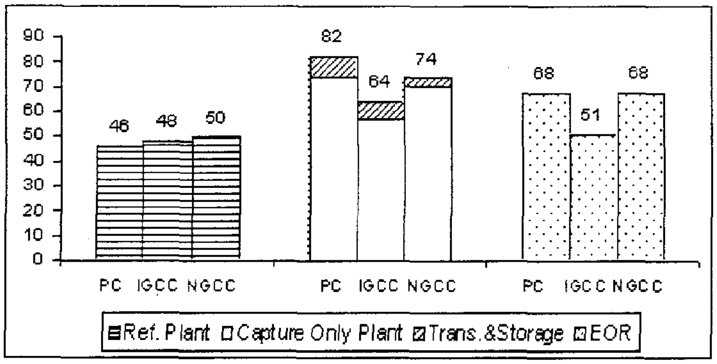


Figure 2. Cost of electricity ($/MWh) for differential capacity factors (CF). (CF for reference plants: PC=IGCC=75%, NGCC=50%; CF for capture plants: PC=75%, IGCC=85%, NGCC=50%)

question the common assumption of using the same fixed charge factor (or rate of return) for all technologies in comparative cost studies. Rather, a risk premium might be required to finance an IGCC project. On the other hand,because of the perceived benefits of IGCC with CO_2 capture, several efforts are underway to develop more attractive financing and ownership arrangements in order to facilitate deployment of IGCC in the U.S. power market. If successful, this would preferentially benefit IGCC technology.

To reflect some of the uncertainty in IGCC financing, we analyze two additional scenarios reflecting conditions favorable and unfavorable to IGCC economics. The "Unfavorable" scenario imposes a 20 percent risk premium on the weighted cost of capital for an IGCC plant, yielding a fixed charge rate of 17.3 percent, compared to the nominal value of 14.8 percent used in the earlier analyses. In contrast, the "Favorable" scenario assumes some form of government intervention to facilitate the deployment of IGCC plants, such as through loan guarantees, production credits, purchasing agreements or other policy instruments. We model this intervention as an effective reduction in the fixed charge rate, and for illustrative purposes assume a value of 10.4 percent based on the Harvard 3-Party Covenant proposal [19]. Finally, we add to each scenario a difference in plant utilization factor to reflect favorable or unfavorable operating conditions over the life of the plant. The unfavorable scenario assumes a levelized capacity factor of 65 percent to reflect a higher outage rate or a lack of expected load over the plant lifetime. The favorable scenario assumes a more optimistic value of 85 percent.

Figure 3 displays the COE for these two scenarios in comparison to the baseline scenario shown earlier. In the Unfavorable case the COE increases by up to 25 percent for both the reference and capture plant. In contrast, the Favorable scenario yields up to 27 percent reduction in COE for both the reference and capture plant. On an absolute basis, the COE of the IGCC capture plant is comparable to a PC plant without capture in this scenario.

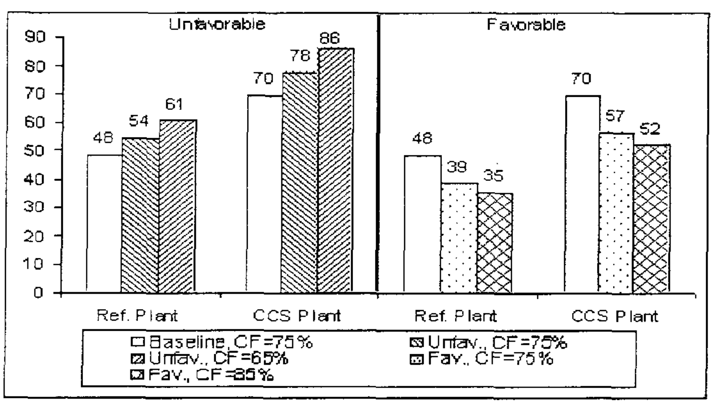


Figure 3. Cost of electricity ($/MWh) for the two new IGCC scenarios. Capacity factor values shown in the legend; fixed charge factor= 14.8% (baseline), 17.3% (unfavorable) and 10.4% (favorable)

CCS ENERGY PENALTY IMPACTS ON COSTS, RESOURCE CONSUMPTION AND ENVIRONMENTAL EMISSIONS

Previous studies have called attention to the significant energy penalties associated with CO_2 capture and storage. The energy penalty of CCS is commonly defined as the reduction in plant output for a constant fuel input (i.e., the plant derating). For some types of facilities, like IGCC plants, the addition of CO_2 capture technology changes both the net plant output and the fuel input. Thus, a more general definition of the energy penalty is based on the change in net plant heat rate or efficiency (η) as given by the following equation:

$$EP = 1 - (\eta_{ccs} / \eta_{ref}) \tag{1}$$

where EP is the energy penalty (fractional reduction in output), and η_{ccs} and η_{ref} are the net efficiencies of the capture plant and reference plant, respectively. As indicated in Table 3, the energy penalties for the three systems modeled in this paper are 24% for the PC plant, 14% for the IGCC plant, and 15% for the NGCC plant. These energy penalties significantly affect the cost of CO_2 capture and storage since a reduction in the net plant output is reflected in higher costs per unit of product and plant capacity. Thus, the normalized capital cost ($/kW) and the overall cost of electricity ($/kWh) shown earlier both incorporate the energy penalty effects, reflecting the added cost of power plant capacity needed to operate the CCS system.

To assess the environmental and resource implications of CCS energy requirements, we propose an alternative definition of the energy penalty that is arguably more useful for this purpose, namely the increase in plant input per unit of product or output. We denote this value as EP*. It is related to EP in Equation (1) by:

$$EP^* = EP / (1 - EP) = (\eta_{ref} / \eta_{ccs}) - 1 \tag{2}$$

This measure is more meaningful because it directly quantifies the increases in resource consumption and environmental burdens associated with producing an increment of some useful product like electricity. In the case of a power plant, this measure directly quantifies the increases per kilowatt-hour in plant fuel consumption, other plant resource requirements (such as chemicals or reagents), solid and liquid wastes, and air pollutants not captured by the CCS system. Indirectly, EP* also affords a measure of the upstream life cycle impacts associated with the extraction, storage and transport of additional fuel and other resources consumed. Numerically, EP* is larger than EP, as seen in Equation (2). The values of EP* for the three case study technologies are 31% for the PC plant, 16% for IGCC, and 17% for the NGCC plant. If current CCS technologies were deployed on a large scale, increases of these magnitudes for a given electricity demand would indeed be significant.

Table 5 summarizes the major ancillary impacts of CCS energy requirements for the three case study plants. Increases in specific fuel consumption correspond directly to the EP* values given above. Other increases in resource requirements for the PC plant include limestone consumed by the flue gas desulfurization (FGD) system (for SO_2 control), and ammonia consumed by the selective catalytic reduction (SCR) system (for NO_x control). Sorbent requirements for the CO_2 capture units also are reported in Table 5, along with the resulting waste streams. Table 5 further shows the increases in ash and slag residues, plus the increases in solids produced by the desulfurization systems for the PC and IGCC plants. The latter residues could constitute either a solid waste or a saleable byproduct, depending on markets for gypsum (PC plant) and sulfur (IGCC plant).

Lastly, Table 5 displays the increased rates of criteria air pollutants due to energy penalty effects. For the PC plant, the amine scrubber captures nearly all residual SO_2 in the power plant flue gas, resulting in a net decrease in SO_2 emissions per kWh. For the IGCC system, there is also some additional capture of residual H_2S along with CO_2, but the net effect is still an increase in emissions per kWh. For NO_x, the emission rate increases for all three systems, as the CO_2 capture units remove little or no nitrogen. The PC plant exhibits the largest increase since it has the largest NO_x emission rate as well as the largest energy penalty. Increases in NH_3 emissions for the PC and NGCC plants are due mainly to chemical reactions within the amine CO_2 capture system [11].

Table 5. Impacts of CCS system and energy penalties on plant resource consumption and emission rates (capture plant rate and increase over reference plant rate)

Capture Plant Parameter	PC		IGCC		NGCC	
	Rate	Increase	Rate	Increase	Rate	Increase
Resource Consumption	(all values in kg/MWh)					
Fuel	390	93	361	49	156	23
Limestone	27.5	6.8	-	-	-	-
Ammonia	0.80	0.19	-	-	-	-
CCS Reagents	2.76	2.76	0.005	0.005	0.80	0.80
Solid Wastes/ Byproduct						
Ash/slag	28.1	6.7	34.2	4.7	-	-
FGD residues	49.6	12.2	-	-	-	-
Sulfur	-	-	7.53	1.04	-	-
Spent CCS sorbent	4.05	4.05	0.005	0.005	0.94	0.94
Atmospheric Emissions						
SO_x	0.001	- 0.29	0.33	0.05	-	-
NO_x	0.77	0.18	0.10	0.01	0.11	0.02
NH_3	0.23	0.22	-	-	0.002	0.002

THE ROLE OF ADVANCED TECHNOLOGY

The case studies in this paper deal only with currently commercial technologies for power generation and CO_2 capture. Significant R&D efforts are underway worldwide to develop more efficient, lower-cost technologies for energy conversion and environmental control. To the extent these efforts prove successful, the environmental and cost impacts of CCS may look very different in the future. Ongoing development of the IECM at Carnegie Mellon will soon include preliminary cost and performance models for a number of advanced power systems and CO_2 capture options, including oxyfuel combustion, advance (membrane-based) oxygen production, advanced IGCC systems (incorporating improved gasifiers and gas turbines), and more efficient PC and NGCC plants using post-combustion capture technologies. These new models will be used for future assessments of alternative CCS options for new and existing fossil fuel power plants.

CONCLUSIONS

This paper has summarized the results of recent studies of CO_2 capture costs for fossil fuel power systems, and presented new comparisons of PC, NGCC and IGCC systems covering a wider range of assumptions for key parameters. In particular, the effects of higher natural gas prices and differential plant utilization rates were highlighted, along with plant financing and operating assumptions for IGCC plants. Failure to include CO_2 transport and storage costs in addition to CO_2 capture costs also was shown to affect comparisons of alternative systems. Using the IECM computer model, we also highlighted the ancillary impacts of CCS energy requirements on plant resource requirements and environmental emissions. While some CCS technologies offer ancillary benefits via the co-capture of criteria air pollutants, the increases in specific fuel consumption, reagent use, and solid wastes associated with current CCS systems are significant. Advanced power generation and CCS technologies offering improved efficiency and lower energy requirements are needed to reduce these impacts.

ACKNOWLEDGEMENTS

Support for this work was provided by the U.S. Department of Energy under Contract No. DE-FC26-00NT40935 from the National Energy Technology Laboratory (DOE/NETL), and by the Carnegie Mellon Electricity Industry Center under grants from EPRI and the Sloan Foundation. The authors alone, however, are responsible for the content of this paper. The authors are grateful for the assistance of Michael Berkenpas in facilitating use of the IECM computer model for this study, and to Dr. John Davison for contributions to the data underlying Table 1.

REFERENCES

1. Riahi, K., Rubin, E. S. and L. Schrattenholzer, 2003: Prospects for carbon capture and sequestration technologies assuming their technological learning, Proceedings of 6th International Greenhouse Gas Control Technologies, 1-4 October, 2002, Kyoto, Japan, J. Gale and Y. Kaya (Eds), Pergamon.
2. EIA, 2001. Annual Energy Outlook 2002 (with Projections to 2020), DOE/EIA-0383(2002), Energy Information Administration, U.S. Department of Energy, Washington, DC.
3. Chiesa, P. and S. Consonni, 1999: Shift reactors and physical absorption for low-CO2 emission IGCCs, Journal of engineering for gas turbine and power, April, Vol. 121
4. EPRI, 2000: *Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal*, Palo Alto, CA, December.
5. Gambini, M. and M. Vellini, 2000: CO2 emission abatement from fossil fuel power plants by exhaust gas treatment, in Proceedings of 2000 International Joint Power Generation Conference. Miami Beach, FL.
6. IEA GHG, 2000: Leading options for the capture of CO_2 emissions at power stations, IEA Greenhouse Gas R&D Programme, Cheltenham, UK, report PH3/14, Feb.
7. IEA GHG, 2003: Potential for improvements in gasification combined cycle power generation with CO_2 capture, IEA Greenhouse Gas R&D Programme, Cheltenham, UK, report PH4/19, May.
8. Jeremy, D. and H. J. Herzog, 2000: The cost of carbon capture. Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies, 13-16 August 2000, Cairns, Australia.
9. Marion, J., Bozzuto, C., Andrus, H., Mccarthy, M., Sundkvist, S.G., and T. Griffin, 2003: Controlling fossil fuel power plant CO2 emissions – Near term and long range views, 2nd Annual Conference on Carbon Sequestration, May 5-9, 2003, Alexandria, VA, USA.
10. Parsons Infrastructure & Technology Group, Inc., 2002: *Updated cost and performance estimates for fossil fuel power plants with CO_2 removal*, Report under Contract No. DE-AM26-99FT40465 to U.S.DOE/NETL, Pittsburgh, PA, and EPRI, Palo Alto, CA., December
11. Rao, A. B. and E. S. Rubin, 2002: A technical, economic, and environmental assessment of amine-based CO_2 capture technology for power plant greenhouse gas control. *Environmental Science and Technology,* 36, 4467-4475.
12. Simbeck, D., 2002: Private communication, April 17, SFA Pacific, Inc., Mountain View, CA.
13. Undrum, H., Bolland, O., and Aarebrot, E., 2000: Economical assessment of natural gas fired combined cycle power plant with CO2 capture and sequestration, Proceedings of the 5th Greenhouse Gas Control Technologies Conference (GHGT5), 13-16 August, Cairns, Australia, CSIRO Publishing
14. See http://www.iecm-online.com for technical documentation and current public version of the IECM.
15. Rao, A.B., Rubin, E.S., and M.B. Berkenpas, 2004: *An integrated modeling framework for carbon management technologies*, Final report to DOE/NETL (Contract number DE-FC26-00NT40935), from Center for Energy and Environmental Studies, Carnegie Mellon University, Pittsburgh, PA, USA.
16. Rubin, E.S., Rao, A.B. and C. Chen, 2003. The Cost of CO_2 Capture and Sequestration for Fossil Fuel Power Systems, Proceedings of 28th International Technical Conference on Coal Utilization and Fuel Systems, March 10-13, 2003, Clearwater, FL, USA,.
17. Frey, H.C. and E.S. Rubin, 1990: *Stochastic Modeling of Coal Gasification Combined Cycle Systems: Cost Models of Selected Integrated Gasification Combined Cycle (IGCC) Systems*, Topical Report, DOE/MC/24248-2901, NTIS DE90015345, Prepared by Carnegie-Mellon University for the U.S. Department of Energy, Morgantown, West Virginia, June 1990, 307p.
18. Johnson, T. L. and D. W. Keith, 2004: Fossil electricity and CO_2 sequestration: how natural gas prices, initial conditions and retrofits determine the cost of controlling CO_2 emissions. *Energy Policy,* 32, 367-382.
19. Rosenberg, W.G., Alpern, D.C., and M.R. Walker, 2004: *Financing IGCC – 3Party Covenant*, BSCIA Working Paper 2004-01, Energy Technology Innovation Project, Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University, Cambridge, MA 02138, February.
20. EIA, 2004: based on data from www.eia.doe.gov, Energy Information Administration, U.S. Dept of Energy, Washington DC.