S. HRG. 111–1243

OVERSIGHT: EPA'S PROPOSAL FOR FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE

HEARING

BEFORE THE

SUBCOMMITTEE ON CLEAN AIR
AND NUCLEAR SAFETY

OF THE

COMMITTEE ON
ENVIRONMENT AND PUBLIC WORKS
UNITED STATES SENATE

ONE HUNDRED ELEVENTH CONGRESS

SECOND SESSION

JULY 22, 2010

Printed for the use of the Committee on Environment and Public Works

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ONE HUNDRED ELEVENTH CONGRESS
SECOND SESSION

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JULY 22, 2010

OPENING STATEMENTS

WITNESSES

OVERSIGHT: EPA'S PROPOSAL FOR FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE

THURSDAY, JULY 22, 2010

U.S. SENATE,
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
SUBCOMMITTEE ON CLEAN AIR AND NUCLEAR SAFETY,
Washington, DC.

The Subcommittee met, pursuant to notice, at 10 a.m. in room 406, Dirksen Senate Office Building, Hon. Thomas R. Carper (Chairman of the Subcommittee) presiding.

Present: Senators Carper, Inhofe, Voinovich, and Cardin.

OPENING STATEMENT OF HON. THOMAS R. CARPER, U.S. SENATOR FROM THE STATE OF DELAWARE

Senator CARPER. This hearing will come to order.

I welcome one and all for joining us today, our colleagues, our witnesses, and those that are in the audience.

Today's oversight hearing is focused on the EPA's proposal for Federal implementation of plans to reduce interstate transport of fine particulate matter and ozone. Senators will have 5 minutes for their opening statements, and I will recognize after our colleagues have made their opening statements, recognize our panel of witnesses.

Following panel statements we will have two rounds of questions.

There is a signing ceremony at the White House later this morning on a piece of legislation I worked on for 6 years, and I think I am going to go to that.

[Laughter.]

Senator CARPER. But that means we are going to move along fairly expeditiously, not rushed, but we are going to move expeditiously.

As most of the folks in this room know—11:30. The bill signing is at 11:30.

Almost 20 years have gone by since Congress last passed significant revisions to the Clean Air Act. And in those 20 years we have made real progress in reducing our Nation's air pollution.

However, many of our dirtiest polluters have kept polluting, albeit at a somewhat slower rate. Reductions have not kept pace with the public health risks and costs attributed to this harmful air pollution. Simply put, we have to do better, a lot better. And the good news is, we can.

When Senator Alexander and I began working together to clean up our Nation's air about 6 years ago, we faced many challenges. I would just hasten to add that Senator Voinovich and I—and Senator Inhofe as well—were working on it even before Lamar and I teamed up on these issues.

But I want to mention two of the challenges that we face today. The first major challenge that we face is that air pollution causes serious health effects, as we know, including asthma, cancer, brain damage, even death. According to the American Lung Association the majority of Americans, that is more than 175 million people, live in areas where there is enough air pollution to endanger their lives or threaten their health.

The second challenge that we face is that air pollution knows no State boundaries. Air pollution emitted by our oldest and dirtiest fossil fuel power plants doesn't just affect the State in which they are located and the health of the people in those States in which they are located. In fact Mid-Atlantic and Northeastern States like Delaware, like Maryland, like New Jersey, Connecticut, and Rhode Island are located in what I call the end of America's tailpipe. We are among the States that receive a heavy dose of pollution from other States' dirty power plants.

To ensure that States are good neighbors, regional and national regulations of air emissions are crucial. That is what brings us all here today. Over the past 10 years the EPA has attempted to regulate harmful power plant emissions that transport across State boundaries, but the court challenges have stood in their way. In 2005 the EPA issued the Clean Air Interstate Rule, affectionately known as CAIR, to reduce sulfur dioxide and nitrogen oxide emissions in 28 eastern States.

After multiple lawsuits in 2008 the District of Columbia Circuit Court vacated CAIR in its entirety but later modified its decision to remand, allowing CAIR to remain in effect until a new rule was promulgated by the Environmental Protection Agency. The proposed Transport Rule is EPA's response to the Court's concerns.

I believe the EPA has done a good job with the tools that they have to address interstate air pollution. To meet the Court's challenge, the Transport Rule is complex and limits business flexibility. However, it is clear this rule can make possible real gains in further cleaning our air and protecting public health.

Today we will hear more details from EPA about how this complex rule will work. We will also hear from the States, from the environmental community, and from business on what they expect the impacts to be once this rule is implemented.

I believe that EPA has written a rule that meets the Court's demands, but like other rules I expect we will see this rule litigated before the courts in the not too distant future. This is a rule to help meet the 1997 standards, 1997 standards. As we all know it is not 1997 anymore. It is 2010, and it is time we have clarity and certainty on clean air reductions. I believe this Congress needs to pass bipartisan legislation that I co-authored along with Senator Alexander and 14 others of our colleagues, Democrats and Republicans. Legislation that cuts mercury emissions by 90 percent and tightens national emissions of sulfur dioxide and nitrogen oxide. This legislation, as shown by EPA modeling, will save even more lives than the EPA's Transport Rule, at a very low cost to the consumer.

However, it is clear that we should be debating how to strengthen the Clean Air Act so we can save thousands of lives and billions of dollars in health care costs rather than debate whether we should be weakening our ability to clean up the air.

So that is the statement I wanted to offer today.

I am going to call on Senator Inhofe next for his statement. I am glad that you are here, and thank you for your efforts in these venues.

[The prepared statement of Senator Carper follows:]

STATEMENT OF HON. THOMAS R. CARPER, U.S. SENATOR FROM THE STATE OF DELAWARE

Ladies and gentlemen, almost 20 years have gone by since Congress last passed significant revisions to the Clean Air Act. In those 20 years, however, we have made real progress in reducing our Nation's air pollution.

However, many of our dirtiest polluters have kept polluting—albeit at a somewhat slower rate—but reductions have not kept pace with the public health risks and costs attributed to this harmful air pollution.

Simply put, we've got to do better. Much better. And the good news is we can.

When Senator Alexander and I began working together to clean up our Nation's air about 6 years ago, we faced many challenges. I'll mention two of these challenges today.

The first major challenge we face is that air pollution causes serious health effects, including asthma, cancer, brain damage—even death.

According to the American Lung Association, a majority of Americans—more than 175 million people—live in areas where there is enough air pollution to endanger their lives or threaten their health.

The second challenge we faced is that air pollution knows no State boundaries.

Air pollution emitted by our oldest and dirtiest fossil fuel power plants doesn't just affect the State in which they are located. In fact, mid-Atlantic and northeastern States like Delaware, Maryland, New Jersey, Connecticut, and Rhode Island are located at what I call "the end of America's tailpipe."

We are among the States that receive a heavy dose of pollution from other States' dirty power plants.

To ensure that States are "good neighbors," regional and national regulations of air emissions are crucial. And that is what brings us all here today.

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The proposed Transport Rule is EPA's response to the Court's concerns.

I believe the EPA has done a good job with the tools they have to address interstate air pollution.

To meet the Court's ruling, the Transport Rule is complex and limits business flexibility; however, it is clear this rule can make possible real gains in further cleaning our air and protecting public health.

Today, we will hear more details from the EPA about how this complex rule will work. We will also hear from the States, environmental community, and business on what they expect the impacts to be once this rule is implemented.

I believe that EPA has written a rule that meets the Court's demands, but—like other rules—I expect we will see this rule litigated before the Court in the not too distant future.

This is a rule to help meet 1997 standards. 1997. As we all know, it's not 1997 anymore. It's 2010, and it's time we have clarity and certainty on clean air reductions.

I believe this Congress needs to pass bipartisan legislation that I've authored along with Senator Alexander and 14 of my other colleagues. Legislation that cuts mercury emissions by 90 percent and tightens national emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x).

This legislation—as shown by EPA modeling—will save even more lives than the EPA's Transport Rule, at a very low cost to the consumer.

However, it's clear that we should be debating how to strengthen the Clean Air Act so we can save thousands of lives and billions of dollars in healthcare costs rather than debate whether we should be weakening our ability to clean up the air.

OPENING STATEMENT OF HON. JAMES M. INHOFE, U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator INHOFE. Thank you, Mr. Chairman. Thank you for having this hearing and also working together. I said the same thing about Senator Cardin, when he had his legislation here, that we have more of a spirit of cooperation than people on the outside want.

Let me say at the outset, when it comes to reducing real air pollution from power plants the best way to accelerate environmental progress and institute certainty for businesses is through 3-P legislation. I am pleased that our staffs have been working across the aisle to find that common ground. Even if we fall short of reaching agreement we are laying the groundwork for bipartisan legislation in the next Congress.

This is not something that is new for me, as everyone here knows. I supported the 3-P legislation when I was Chairman of the whole Committee, the Environment and Public Works Committee. I tried to advance the Clear Skies Bill, not all that dissimilar from what we are talking about now.

Because that effort eventually failed for reasons we don't need to get into now, we got regulations under the Clean Air Act that the D.C. Circuit ultimately rejected. That is something that Senator Voinovich and I predicted was going to happen. Here is what I said when the Bush administration's Clean Air Interstate Rule was promulgated, the CAIR Rule, and I am quoting now from what I said at that time: "This Clean Air Interstate Rule is significantly more vulnerable to court challenges than legislation and will undoubtedly be held up. Trying to litigate the way to cleaner air only delays progress, often yields little or no result, and wastes millions of taxpayers' dollars."

So here we sit, debating EPA's replacement regulations that, though admirable in their intent, are onerous and complex and vulnerable to the same lawsuits that stymied previous attempts to reduce emissions of SO_x and NO_x.

Like the Bush administration's Clean Air Interstate Rule, EPA's transport rule addressees the transport of fine particles, the PM, and ozone across State lines. This rule, to put it mildly, is not a model for simplicity. For example, as the Clean Air Task Force has noticed under the rule, "EPA will issue four discrete types of new emission allowances for four different cap and trade programs corresponding to four different control regimes." Utilities will also face moving and uncertain emission targets as EPA further tightens national ambient air quality standards, or the NAAQS, for ozone and PM over the next few years.

In my State of Oklahoma this issue of uncertainty, uncertainty over the pending NAAQS revisions and future transport rules, is causing substantial concern. I look forward to addressing this issue with questions to our Assistant Administrator McCarthy.

Also to address legal problems identified by the Court EPA greatly restricted the ability of the utilities to trade emissions rights. I am afraid that these trading restrictions and the resulting and devaluing of the previous banked allowances from the acid rain program have created a lack of confidence in emission trading markets.

Now, on the question of trading, I want to quickly address the argument that trading for SO_x and NO_x is the same as trading for CO_2. This is simply false. We have talked about this in this Committee many times. When the 1990 Clean Air Act Amendments were passed we had commercially available technology as well as low sulfur coal to meet emissions reductions requirements. As two EPA attorneys have noticed with acid rain, "Little new technology or infrastructure was needed, and little was created."

Now, with CO_2 we don't have emission-specific technology. Compliance would come in many cases from shutting down coal. That is why passing restrictions on CO_2 will mean, among other things, higher electricity prices, especially in the Midwest and the South. Serious reliability problems and fewer jobs.

So let's avoid the temptation to re-introduce CO_2 into this debate. I think we have pretty much agreed on that now. We can pass a straightforward 3-P bill that sets clear targets, and I would say achievable targets. We may have to get together and talk about these things, that sets clear targets and timetables and avoids endless litigation that enriches lawyers at the expense of obtaining certain public health and environmental benefits.

We could surprise many in this city who don't think passing bipartisan legislation of this kind is possible. I stand ready to make it happen. And I thank you, Mr. Chairman.

[The prepared statement of Senator Inhofe follows:]

STATEMENT OF HON. JAMES M. INHOFE,
U.S. SENATOR FROM THE STATE OF OKLAHOMA

Chairman Carper, thank you for holding this hearing today to discuss EPA's new Transport Rule.

Let me say at the outset that when it comes to reducing real air pollution from power plants the best way to accelerate environmental progress and institute certainty for businesses is through 3-P legislation. I'm pleased that our staffs are working across the aisle to find common ground that could lead to passage of 3-P legislation this year. Even if we fall short of reaching agreement we are laying the groundwork for bipartisan legislation in the next Congress.

This is not something new for me. I supported 3-P legislation when as chairman of EPW I tried to advance the Clear Skies bill. Because that effort eventually failed for reasons I won't get into now, we received regulations under the Clean Air Act that the D.C. Circuit ultimately rejected—something Senator Voinovich and I predicted would happen. Here's what I said when the Bush administration's Clean Air Interstate Rule was promulgated: "This Clean Air Interstate Rule is significantly more vulnerable to court challenges than legislation and will undoubtedly be held up. Trying to litigate the way to cleaner air only delays progress, often yields little or no result, and wastes millions in taxpayer dollars."

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Utilities will also face moving and uncertain emissions targets as EPA further tightens National Ambient Air Quality Standards (NAAQS) for ozone and PM over the next few years. In my State of Oklahoma this issue of uncertainty over the pending NAAQS revisions and future transport rules is causing substantial concern, and I look forward to addressing this issue with questions to Assistant Administrator McCarthy.

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So let's avoid the temptation to re-introduce CO_2 into this debate. We can pass a straightforward 3-P bill that sets clear targets and timetables and avoids the endless raft of litigation that enriches lawyers at the expense of attaining certain public health and environmental benefits. We could surprise many in this city who don't think passing bipartisan legislation of this kind is possible. And I stand ready to make it happen.

Thank you.

Senator CARPER. I thank you for that spirit and very much for your statement.

We have been by one of our co-sponsors of our legislation. I want to thank Senator Cardin for becoming a co-sponsor, and I want to thank you very much for being here today.

Thank you. Welcome. You are recognized.

OPENING STATEMENT OF HON. BENJAMIN L. CARDIN, U.S. SENATOR FROM THE STATE OF MARYLAND

Senator CARDIN. Mr. Chairman, let me congratulate you; as I have said before, you have taken steps, I think, to bring us together on an extremely important legislation with 3-Ps. Senator Inhofe, thank you for your kind comments at the beginning of your testimony. You are right; when we work together we get things done. We also get better bills.

So I hope that what we are doing here in this Committee in trying to bring us together on important environmental legislation can be a model for the type of civility that yields good results for the people of this Nation. Thank you both, and Senator Carper, as you know, you have been a real champion on this issue.

And I thank you for your patience. We are getting closer, and we are making a lot of progress. Maryland has taken aggressive steps to reduce air pollution emissions within the State. In 2007 Maryland passed the Healthy Air Act, the country's most aggressive clean air legislation. Using 2002 as its emission baseline the Healthy Air Act has Maryland well on its way to reducing the State NO_x emissions by 75 percent by 2012 after already achieving an interim goal of 70 percent reduction targets on NO_x in 2009.

SO_x emissions will reduce by 80 percent this year with the second phase of controls in 2013 achieving 35 percent SO_2 emission reductions. Despite Maryland's successful efforts to reduce its in-State emissions of ground level ozone and $PM_{2.5}$-causing emissions, pollution from upwind States prevent Maryland from reaching attainment under the Clean Air Act. On most bad air days somewhere between 50 percent to 75 percent of Maryland's air pollution originates in upwind States.

This June the Baltimore and Washington metropolitan areas experienced 22 moderate and unhealthy air days. Mr. Chairman, that is why your bill is just so important to this country and Maryland. More than 2 million Marylanders suffer from respiratory and cardiovascular diseases like asthma, emphysema, and diabetes. Unhealthy air days exacerbate health problems for at-risk populations that cost Americans billions of dollars in health care costs, loss of wages due to illnesses triggered by bad air that leads to absences from work and school.

EPA's new proposed Transport Rule is a step toward addressing the persistent clean air issue Mid-Atlantic and Northeast States face. The Rule requirements for power plants to finally install modern pollution control technology across most of the eastern half of the United States is long overdue.

However, EPA acknowledges that even with the new Clean Air Transport rules in place there will still be municipalities that will continue to struggle with meeting attainment as indicated throughout our region. Baltimore City and Anne Arundel County, Maryland, are two jurisdictions that are projected to have maintenance problems even with the new Transport Rules in place. This new rule is an important first step, but clearly there is more work that needs to be done.

Fortunately, there are opportunities on the horizon to achieve emission reductions needed to allow all States to achieve attainment. I am committed to working with Chairman Carper and the members of this Committee so that we can achieve the type of national legislation to assist EPA in the work that it is doing and the work that is being done by many of our States.

Mr. Chairman, again, thank you for your leadership. I look forward to working with you.

[The prepared statement of Senator Cardin follows:]

STATEMENT OF HON. BENJAMIN L. CARDIN,
U.S. SENATOR FROM THE STATE OF MARYLAND

Thank you, Senator Carper, for holding this hearing today to examine EPA's proposed Clean Air Interstate Rule. I appreciate our witnesses taking the time to come before your Subcommittee to discuss the important work that is being done to better protect our air quality.

I know, Senator Carper, this is an issue you care deeply about and have spent a great deal of your career working on. I appreciate the time and attention that you and this Subcommittee spend on this important human health issue.

Senator Carper and I understand the importance of addressing air pollution transport as it affects the health of our constituents living in or neighboring downwind States located at "America's Tailpipe." For this reason I appreciate that EPA is in the process of addressing the issue of air pollution transport through its new Transport Rule.

Maryland has taken aggressive steps to reduce air pollution emissions within the State. In 2007 Maryland passed the Healthy Air Act, the country's most aggressive clean air legislation.

Using 2002 as its emissions baseline the Healthy Air Act has Maryland well on its way to reducing in-State NO_x emissions by 75 percent by 2012 after already achieving an interim goal of 70 percent reduction target for NO_x in 2009.

SO_2 emissions will be reduced by 80 percent this year with a second phase of controls in 2013 to achieve 85 percent SO_2 emission reductions.

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On most bad air days somewhere between 50 percent and 75 percent of Maryland's air pollution originates in an upwind State. This June the Baltimore and Washington metropolitan areas experienced 22 moderate and unhealthy air days.

More than 2 million Marylanders suffer from respiratory and cardiovascular diseases like asthma, emphysema, and diabetes.[1] Unhealthy air days exacerbate health problems of at-risk populations and cost Americans billions of dollars in health care costs and lost wages due to illnesses triggered by bad air that lead to absences from work and school.

EPA's newly proposed Transport Rule is a step toward addressing the persistent clean air issues Mid-Atlantic and Northeast States face. The rule's requirement for power plants to finally install modern pollution control technology across most of the eastern half of the United States is long overdue.

However, EPA acknowledges that even with the new Clean Air Transport Rule in place there will still be municipalities that will continue to struggle with meeting attainment, as indicated on this map.

Baltimore City and Anne Arundel County, Maryland, are two jurisdictions that are projected to have "maintenance problems" even with the new Transport Rule in place. This new rule is an important first step, but clearly there is more work that needs to be done.

Fortunately, there are opportunities on the horizon to achieve emissions reductions needed to allow all States to achieve attainment.

I am committed to working to make sure that the Federal Government's efforts keep pace with and support the hard work Maryland is doing at the State level to protect Marylanders from unhealthy air.

I want to urge EPA and my colleagues to continue working toward the goal of eliminating bad air days. I look forward to working with Senator Carper and other members of this Committee to achieve this end.

Thank you, and I look forward to hearing the testimony of our witnesses.

Senator CARPER. We look forward to being your partner, and again, thanks very, very much.

Senator Voinovich has worked on these issues I think probably for longer than I have. Unfortunately he is thinking of leaving us at the end of the year. He is on a mission—and I am, too—to make sure that a number of items on his agenda list get completed. This could be part of his legacy, and I think part of the legacy of this Committee. So thank you very much for all the work and the effort you have put into this. My hope is that we will find by the end of this year it will have been for a very, very good purpose.

Senator Voinovich.

OPENING STATEMENT OF HON. GEORGE V. VOINOVICH, U.S. SENATOR FROM THE STATE OF OHIO

Senator VOINOVICH. Thank you, Senator Carper. I smile because I can still remember when Senator Jeffords was Chairman of this Committee, and we were talking about the same thing 8 years ago.

I just would like to start out right now with a big picture thing. If you look at what we have done in health, we have looked at financial regulations, we are talking about climate change, this air rule, the CAIR Rule, issue of taxation, there is more uncertainty today in this country than I have ever seen in my entire life. There was a recent article in Newsweek by Fareed Zakaria who talked about the fact that we are sitting on about $2 trillion—businesses are, not doing anything because they just don't know where we are

[1] According to the American Lung Association's "2010 State of the Air" Report Card for Maryland.

going. So they are just kind of sitting back and trying to figure out, where are we going.

I think that is kind of a backdrop. The other is that I heard Senator Cardin's statement about all of the health problems that we have. From my side you will be hearing a lot about what the costs are for the companies and the people and so on and so forth.

The problem is that in terms of the cost-benefit, we don't get into that. According to what I know Ms. McCarthy doesn't have to consider that part of it. She has to consider the health part of it. When you do the Water Rule you have cost-benefit analysis, you have peer review, you have alternative regulations, et cetera. So we have never got there. And frankly, when I first came here, the first couple of years, I tried to get cost-benefit put in the air and just got blasted out. Just a terrible thing, we should never do it and so forth.

But that is a fundamental thing that I think we all need to talk about one of these days. Because that is what we are running into.

Senator CARPER. When we get into questions, one of the questions I will be asking of the Administration is about cost and benefit.

Senator VOINOVICH. So I would like to say that I am glad that you are calling this today. I am glad that Chris Korleski, head of Ohio's Department of Environmental Protection, is one of the witnesses. And I am anxious to hear everyone's thoughts about the EPA's proposed Transport Rule.

As the Chairman knows, I have long sought a national policy that implements a comprehensive air quality strategy that helps attain our Nation's Ambient Air Quality Standards and streamlines Clean Air Act requirements. I have been working—the first thing I did when I became Governor was to get Ohio to comply with the Ambient Air Standards because I knew its impact when I was Mayor, and we needed to get on with this. It had real, not only health benefits, but it also had economic benefits.

I did sponsor the Clear Skies Act, and the Chairman and I know—we spent a lot of time on it. When the Court overturned EPA's first Interstate Transport Rule, CAIR, and the mercury rule, it left us with no comprehensive or cost effective policy to reduce emissions or untangle the complicated web of overlapping and redundant regulations affecting power plants. Senator Inhofe said this, we both feared, and it happened.

EPA's Transport Rule does not allay these concerns. In fact, the proposal presents a string and inflexible regulatory regime that may be unworkable as a practical matter. If the agency finalizes its rule on schedule, spring of 2011, it would allow for little more than 6 months for compliance. Then a mere 2 years later a second phase of caps would kick in, reducing SO_2 and NO_x by 71 and 52 percent, respectively.

These timeframes do not recognize the realities associated with designing, permitting, and installing the equipment to meet the mandates. Because the proposal virtually eliminates emission trading the regulatory hurdles will be all that much greater. Adding to the challenge, EPA is proposing to revise the emission caps as new NAAQS are promulgated. This means that the electric sector will face ever changing compliance hurdles that will provide little clarity for business planning.

With the added uncertainty of future greenhouse gas controls, the potential regulation of coal ash as a hazardous waste, the electric power industry is facing an uncertain and chaotic situation that I believe is incumbent upon Congress to fix. And the chart behind me is an indication of what they are going to be confronting, 2008 over here to 2017.

This is what I am looking at, if I am running a utility company. Just think about this. Senator Carper, if we could work something out, we could eliminate all of this stuff, or most of it, so that people know where they are going, what am I going to have to do, how much am I going to have to invest, what am I going to have and so forth.

And this fear that I have is not unfounded. The 2009 National Energy Technology Laboratory analysis titled GDP Impacts of Energy Costs found that if 25 percent of the Nation's coal generating capacity is replaced with natural gas or renewables, electricity prices would increase by 25 percent, GDP would decrease by 2.6 percent, and the economy would shed nearly 3 million jobs. I would like to submit a copy of that report for the record.

Senator CARPER. Without objection, so ordered.

Senator VOINOVICH. Then you compare this to a recent Edison Electric Institute analysis that depicts the cumulative effect of pending EPA rules on the electric power sector. This analysis shows that the agency's actions have the potential to shutter over 120,000 megawatts of coal-fired generation by 2015. This is over 38 percent of our country's coal fleet. And I would like to submit a copy of that report for the record.

Senator CARPER. Without objection, so ordered.

Senator VOINOVICH. Indeed, a major service provider in Ohio, AEP, projects that pending EPA regulations would cause them to shutter 4,000 to 6,000 megawatts, 20 to 35 percent of their coal-fired capacity, in their near eastern service area in the 2014–2015 timeframe. I have detailed testimony from AEP, and I would like to have that submitted for the record.

Senator CARPER. Without objection, so ordered.

Senator VOINOVICH. We can alleviate these concerns by properly coordinating the compliance obligations for the electric power sector while giving the industry a predictable compliance road map over the next 10 to 20 years. This would promote efficiency, allow companies to make strategic error investments to reduce emissions and provide electric reliability.

For these reasons a 3-P strategy continues to make sense. I am appreciative of the Carper-Alexander legislation. As you know, we are trying to work together to see if we can't get something done in that arena. I would love to do it, because maybe we wouldn't be here 5 years from now talking about the same subject.

Thank you.

[The referenced material follows:]

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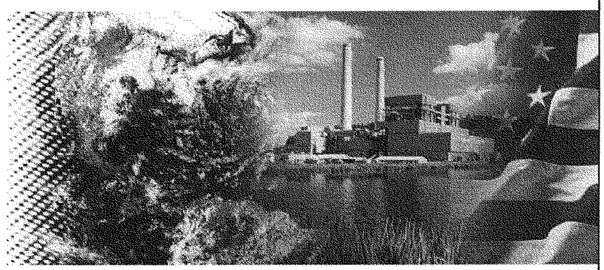

GDP Impacts of Energy Costs

October 5, 2009

DOE/NETL- DOE/NETL- 402/083109

U.S. DEPARTMENT OF ENERGY

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GDP IMPACTS OF ENERGY COSTS

DOE/NETL-402/083109

FINAL REPORT
October 5, 2009

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EXECUTIVE SUMMARY

This report analyzes the relationship between energy prices and economic variables such as GDP and employment. Specifically it:

- Analyzes the short-run and long-run theoretical relationship between energy costs and GDP
- Estimates the current and forecast costs of the major electricity generation options: Fossil, nuclear, and renewables
- Analyzes estimates of the elasticity of GDP with respect to energy prices
- Develops a methodology and spreadsheet tool that allows estimation of the impact of electricity prices on GDP and jobs
- Uses the tool developed to conduct analyses and simulations of various policy and price scenarios through 2030
- Uses the results obtained to derive implications concerning the role of energy prices in the economy and NEMS handling of the relationship between GDP and energy costs

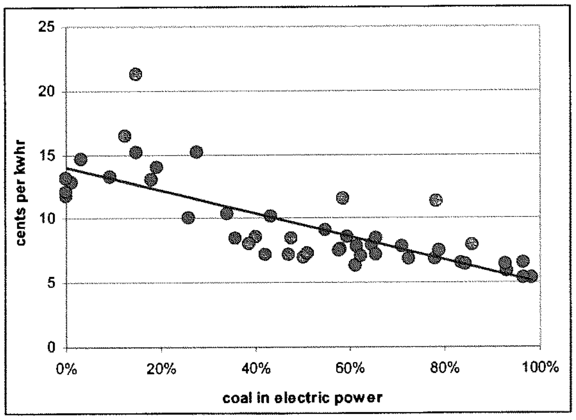
The research conducted here finds that most economists who have analyzed the issue agree that there is a negative relationship between energy price changes and economic activity, but there are significant differences of opinion on the economic mechanisms through which price impacts are felt. Estimates of the impacts of oil shocks have produced different results with smaller time-series econometric models producing energy price change-output elasticities of -2.5 percent to -11 percent, while large disaggregated macro models estimate much smaller impacts – in the range of -0.2 percent to -1.0 percent.

Coal is currently the low-cost option for generating electricity and is forecast to remain so. As shown in Figure EX-1, there is a negative relationship between electricity prices and a state's use of coal to generate electricity: The higher percentage of coal used to generate electricity, the lower the electricity rate.

In terms of both fuel prices and levelized cost of electricity (LCOE) coal is the low-cost option for producing electricity – Figure EX-2.

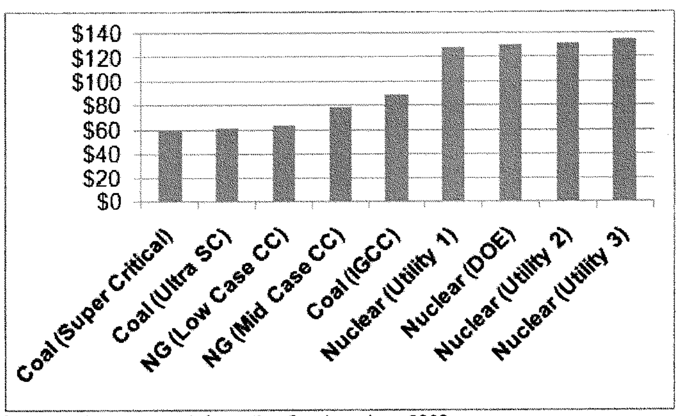
Future LCOE costs are difficult to estimate, but EIA and others may be underestimating future LCOEs for nuclear and renewables. Especially for renewables, proper accounting for capacity factors, intermittency, reliability, back-up power, transmission requirements, and subsidies may significantly increase the actual LCOEs.

Figure EX-1
The Relationship of State Average Electricity Prices and Coal Fuel Inputs – 2007



Source: U.S. Energy Information Administration, *Selected Electric Industry Summary Statistics by State* and *Electric Power Sector Consumption Estimates*; and Management Information Services, Inc., 2009.

Figure EX-2
Estimated Levelized Costs per MWH



Source: Management Information Services, Inc., 2009.

Review of the literature revealed a number of studies that estimated the energy price/GDP elasticities – Table EX-1. On the basis of this review and an analysis of studies conducted to estimate the impact on GDP of changes in energy prices, we determined that a reasonable elasticity estimate is -0.1, which implies that a 10 percent increase in energy prices will result in a one percent decrease in GDP.

Table EX-1
Summary of Energy-GDP Elasticity Estimates

Year Analysis Published	Author	Elasticity Estimate
2009	Blumel, Espinoza, and Domper	-0.85 to -0.16
2008	Kerschner and Hubacek	-0.03 to -0.17
2008	Sparrow	-0.3
2007	Maeda	-0.03 to -0.75
2007	Citigroup	-0.3 to -0.37
2007	Lescaroux	-0.1 to -0.6
2006	Rose and Wei	-0.1
2006	Oxford Economic Forecasting	-0.03 to -0.07
2006	Considine	-0.3
2006	Global Insight	-0.04
2004	IEA	-0.08 to -0.13
2002	Rose and Young	-0.14
2002	Klein and Kenny	-0.06 to -0.13
2001	Rose and Ranjan	-0.14
2001	Rose and Ranjan	-0.05 to -0.25
1999	Brown and Yucel	-0.05
1996	Rotemberg and Woodford	-0.25
1996	Gardner and Joutz	-0.072
1996	Hewson and Stamberg	-0.14
1996	Hooker	-0.07 to -0.29
1995	Lee and Ratti	-0.14
1982	Anderson	-0.14
1981	Rasche and Tatom	-0.05 to -0.11

Source: Management Information Services, Inc., 2009.

A methodological tool was developed here that permits the estimation of the economic and jobs impacts of changes in energy-related assumptions and variables. The major parameters of the tool include dollar base, forecast year, electricity generation options, electricity demand, electricity production among the generation options, LCOEs of the electricity generation options, average price of electricity, elasticity of GDP with respect to electricity prices, GDP, GDP/jobs relationships, and others. The 2010 basic reference parameters are shown in Table EX-2. The tool is flexible enough to consider many variations in assumptions and variables, and it can be augmented and expanded.

Table EX-2
2010 Reference Parameters

Electric Power Sector – 2010	Tbtu	Percent	c/kWh
Coal	20.7	51%	6.9
Nuclear	8.5	21%	11.0
Natural Gas	6.1	15%	7.8
Onshore Wind	1.1	3%	17.4
Other	4.1	10%	8.1
Hydroelectric	*2.7*	*7%*	6.2
Geothermal	*0.2*	*0%*	10.0
Offshore Wind	*0.0*	*0%*	29.3
Solar Thermal	*0.0*	*0%*	32.9
PV	*0.0*	*0%*	49.3
Petroleum	*0.6*	*1%*	14.0
Biomass	*0.3*	*1%*	10.3
Other	*0.3*	*1%*	10.0
Total	40.5	100.0%	
Calculated average price of electricity (cents/kWh)			8.30
2010 reference price of electricity (cents/kWh)			8.30

This results in an increase of electricty prices of:	0.0%
With electricity accounting for total U.S.	
2010 energy consumption at	100%
and GDP (trillion 2007$) at:	$11.6
and the elasticity of output to energy price of:	0.1
.......the reduction in U.S. GDP (billion 2007$) is:	$0.0
With the average U.S. jobs/billion$ GDP ratio at :	10,200
.....the reduction in U.S. jobs (thousand FTE) is:	0

Source: Management Information Services, Inc., 2009.

Five analyses were conducted using the methodology and tool to obtain insight into the level of feedback to GDP that may be captured by NEMS:

- 2010 Test Case Scenarios
- 2020 Decarbonization Scenarios
- Assessment of the EIA Analysis of the Lieberman-Warner Bill
- Assessment of the High Macro $30 carbon tax case (from Activity III)
- Assessment of the High Renewables-based Power case (from Activity III)

2010 Test Case Scenarios

Hypothetical test case scenarios were conducted to obtain an indication of the likely impact of substantially reducing U.S. coal-fired electricity generation in the near future and replacing it with natural gas and renewables. It was hypothesized that in 2010 coal-fired electricity generation is reduced by 25 percent and that half of the reduction is replaced by an increase in natural gas generation and half by increased renewables. The findings indicated that the 2010 economic and jobs impacts are significant and may result in:

- Average electricity prices increases of nearly 25 percent
- GDP reduction of $285 billion (2007 dollars) – 2.6 percent
- Job losses of 2.9 million – slightly more than two percent

2020 Decarbonization Scenarios

A proposal to transform the U.S. electricity grid to carbon-free energy within 10 years was analyzed, and several simulations were conducted of the likely economic and jobs impact in 2020 of the proposal. The findings indicated that the economic and jobs impacts of the 2020 decarbonization proposal may be severe:

- Average electricity prices could increase by 50 – 80+ percent
- GDP could be reduced by $700 billion to nearly $1.3 trillion (2007 dollars) – about five to over eight percent
- Job losses could total 6.3 million to nearly 11 million – about four to seven percent.

Assessment of the EIA Analysis of the Lieberman-Warner Bill

An assessment was made of the EIA projection of the economic impacts of the Lieberman-Warner Climate Security Act of 2007, which would regulate GHG emissions through market-based mechanisms. The objective was to assess the reasonableness of the EIA findings of the likely economic and jobs impact of LW, and the findings indicated that:

- The increase in electricity prices under the EIA scenarios analyzed would be somewhat higher than estimated by EIA.
- The GDP and jobs losses under the EIA scenarios analyzed would be much higher than estimated by EIA.
- The EIA methodology and NEMS implicitly assume that increased electricity prices have relatively little impact on GDP or jobs.

The lack of impact in the EIA report of electricity prices on GDP or jobs is difficult to reconcile with decades of results reported in the literature, and the implication in the EIA analysis that the elasticity estimate is virtually 0 is open to question. This is an important issue deserving of further research.

Assessment of the High Macro $30 Carbon Tax Case

The results of the NEMS High Macro $30 carbon tax case (from Activity III) were analyzed to obtain insight into the level of feedback to GDP that may be captured by NEMS. The analysis raised some questions about the NEMS-generated results. For example, the High Macro case represents a major shift away from coal and NG and in favor of nuclear power and renewables, and electricity prices in 2030 are 34 percent higher than in the ARRA reference case. However, using NEMS data, it is difficult to simulate electricity prices that high.

Second, NEMS is forecasting that real GDP will increase 3.3 percent annually, 2010 through 2030 – a rather high long term real growth rate, especially when total electricity consumption is growing at only one percent annually over the same period.

Third, NEMS forecasts a very large growth in U.S. exports over the period, increasing from 11 percent of GDP in 2010 to 25 percent in 2030 – increasing 7.3 percent annually, and by the latter year the U.S. has an export surplus of nearly $700 billion (2007 dollars). This is questionable – especially when electricity consumption is increasing only one percent annually.

Under the High Macro case, real U.S. 2030 GDP will be 12 percent higher ($6.3 trillion in 2007 dollars) than under the ARRA reference case, and this may not be consistent with the fact that electricity prices under the High Macro case are 34 percent higher than under the ARRA reference case. This also indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is actually positive: Increased electricity prices increase GDP. This is contrary to results reported in the literature and differs from the results derived here using the tool

Assessment of the High Renewables-based Power Case

The results of the NEMS High Renewables-based Power case (from Activity III) were analyzed to obtain insight into the level of feedback to GDP that may be captured by NEMS. The analysis indicated that the NEMS-generated results for this case generated less variance than did the High Macro case. For example, the High Renewables case represents a major shift away from coal in favor of renewables, but electricity prices in 2030 are only about three percent higher than in the ARRA reference case. Using the NEMS data indicates that electricity prices should be somewhat higher – in the range of 10.5¢/kWh to 11¢/kWh, six to 12 percent. However, given the uncertainties inherent in any forecasts, it is not clear that these differences are statistically significant.

Second, NEMS is forecasting that real GDP will increase 2.7 percent annually, 2010 through 2030. For the U.S., this would represent good economic performance, but something that may be achievable.

Finally, under the High Renewables case, real U.S. 2030 GDP will be virtually identical to GDP under the ARRA reference case, which indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is zero. This is contrary to studies in the literature but, given the small increase in electricity prices it may not be significant.

Using the tool indicates that under the High Renewables case:

- A three percent increase in electricity prices implies that 2030 GDP should be about $70 billion less and that total jobs should be about 500,000 less than forecast using NEMS.
- Using the mean estimate of the MISI electricity price forecasts indicates that 2030 GDP should be about $330 billion less and that total jobs should be about 1.6 million less than forecast using NEMS.

Summary of Major Findings

The major findings of the research reported here are:

- Energy and energy prices affect GDP, and there is a negative relationship between energy price changes and economic activity.
- The U.S. economy is still heavily dependent on energy, and this dependency can be measured by how much output can be created by a given energy input.
- Electricity is increasing in importance in the U.S. economy and thus the impact of electricity and electricity prices on GDP and other economic variables will be gradually increasing over time.
- NEMS may not adequately capture the impacts on GDP of changes in energy costs, and a methodology and tool were developed here to explore this relationship. The tool quantifies the relationship between electricity prices and the economy and permits the estimation of the economic and jobs impacts of changes in energy-related assumptions and variables.
- The tool cannot compare to NEMS or similar large scale econometric models, but it can offer valuable insights and can provide advantages in terms of cost, transparency, ease of use, and rapid turnaround over very large, complex models.
- Analyses were conducted using the tool to obtain insight into the level of feedback to GDP that may be captured by NEMS, and these analyses indicated that:
  - The economic and jobs impacts of displacing coal generation could be significant in terms of electricity price increases, reduction in GDP, and job losses
  - Attempts to "decarbonize" electricity generation by 2020 may have severe impacts on the U.S. economy and job market

- The EIA methodology and NEMS seem to imply that increased electricity prices have relatively little impact on GDP or jobs
- NEMS may underestimate the impact of coal displacement scenarios on GDP and jobs

I. THEORETICAL ANALYSIS OF THE RELATIONSHIP BETWEEN ENERGY COSTS AND GDP

Beginning with the oil supply shocks of the 1970's, analyses that have addressed the impact of energy price shocks on economic activity have produced, and continue to produce, a steady stream of reports and studies on the topic. No attempt to comprehensively review this large body of literature is made here.[1] Rather, here we present an overview of the major issues that have been raised by these studies, the different paths of analysis that have been taken, and the major findings that have significant -- although not always universal -- support.

This overview first analyzes the issues surrounding attempts to gauge the short-run impacts of energy price changes and then examines some of the issues involved in studies of the long-run impacts. The latter section includes a brief summary of some of the new directions in growth theory that integrate energy as an explanatory factor into long-term growth models.

I.A. Short-Run Effects

Following the two disruptive oil shocks of the 1970's, what began as a seemingly straight forward attempt to establish the quantitative relationship between oil price changes and the economy has evolved over the last three decades into an ongoing scholarly debate. While most economists who have examined this issue agree that there is an inverse relationship between energy prices and economic activity, there is little agreement as to the size of the relationship, the channels through which energy price changes alter economic activity, or how stable the relationship might be, to list just three of the areas of dispute.

James Hamilton is generally credited with writing the first influential paper to demonstrate that there was causality that ran from oil price increases and U.S. recessions.[2] In his paper, Hamilton argued that oil price increases had been responsible for all but one of the U.S. recession since the end of WWII. Other scholars produced studies that supported Hamilton's findings, either with respect to the U.S. economy or with respect to the economies of other countries.

[1]The body of literature on this topic is large and there are several relatively recent reviews of this literature. See, for example, Donald E. Jones, Paul N. Leiby and Inja K. Paik, "Oil Price Shocks and the Macroeconomy: What Has Been Learned since 1996", *The Energy Journal*, Vol. 25, No. 2, 2004. (This paper is an update of an earlier review that Jones and Leiber authored in 1996.); Lutz Kilian, "The Economic Effects of Energy Price Shocks", *Journal of Economic Literature*, Vol. 46, No. 4, 2008, pp. 871-909; Stephen P.A. Brown, et al, "Business Cycles: The Role of Energy Prices", FRB of Dallas Working Paper, Number 0304; Paul Segal, "Why Do Oil Price Shocks No Longer Shock?" WPM 35, Oxford Institute for Energy Studies, New College, Department of Economics, University of Oxford. October 2007.
[2]James D. Hamilton, "Oil and the Macroeconomy since World War II," *Journal of Political Economy*, vol. 91, 1983, pp. 228-248.

As this work progressed, it was not long before researchers began to find anomalies in the published research that raised questions about how solid the economic relationship between oil prices and economic activity actually was. Some of the more contentious issues concerned the mechanisms through which oil price changes impacted economic activity, the reason or reasons why oil price impacts apparently were asymmetric - - causing economic recessions when prices increased, but producing no economic boom when prices declined, as they did during much of the 1980's, and whether or not it was oil price shocks or something else (monetary policy) that caused the reaction.

One of the earliest questions raised asked how increases in the price of oil, even as large as those experienced during the 1970's, could cause such disproportionally large decreases in economic output, since the value of oil consumed in the economy was such a small share of total output -- around three to five percent. The standard model for assessing the impact of an oil change was a neoclassical production function that related real economic output, Y, to inputs of capital, K, labor, L, and energy, E.

$$Y = F(K,L,E)$$

In a competitive market, firms would buy a resource input, say energy, up to the point where the price of the input was equal to the marginal value product of the input,

$$P_E = pF_E(L,K,E)$$

where P_E is the partial derivative of F with respect to E. Multiplying both sides of this equation by E (Energy) and dividing by pY (the value of total output) results in the equation

$$P_E\,E/pY = pF_E(L,K,E)E/Y$$

The left side of the equation shows the value of energy as a share of total output and the right side is the elasticity of output with respect to energy use. Since the share of energy in total output was, as noted, relatively small, how could the analysis explain the relatively large changes in output? As a result of the conundrum, research turned to looking for alternative routes by which oil price changes could impact output.

The description above of the anticipated impact of an oil price shock operating through production, as an increase in the price of an input, is an example of a supply shock to a market. The increase in the input price results in a supply-side impact to the market. In a competitive equilibrium, one can then analyze what the expected change in output, prices and other variables, such as the interest rate might be. In a classical macro model, a decrease in aggregate supply caused by an increase in oil prices would be expected to raise prices, lower output (GDP) and raise interest rates. Interest rates would increase as consumers, faced with higher prices, save less or borrow more, increasing real interest rates.

These changes – lower output, higher prices, and higher interest rates – describe the changes in the economy that followed the oil price shocks of the 1970's. In other words, the prediction of the theory seemed to be corroborated by the historical record. To match results of the theory with the historical record and to compare these findings with alternative ideas about how oil shocks impact the economy, Brown, et al.[3] created a table which is reproduced below.

Table I-1

Expected Responses to Rising Oil Price

	Real GDP	Price Level	Interest Rate
Historical Record	Down	Up	Up
Classic Supply Shock	Down	Up	Up
Aggregate Demand Shock	Down	Down	Down
Monetary Shock	Down	Down	Up
Real Balance Effect	Down	Down	Up

Source: Steven Brown, Mine K. Yucel, and John Thompson, 2004.

One obvious channel through which energy price impacts might operate is through a decrease in demand, since much oil is imported and the income from the higher prices results in a transfer from domestic consumers to foreign producers who may or may not spend the earnings in the U.S. The loss of real income is comparable to a tax increase and it reduces aggregate demand through four possible channels: [4]

- Higher oil prices reduce discretionary income leading to less spending
- The price shock may create uncertainty and cause consumers to postpone discretionary spending
- Consumers may increase precautionary saving
- Consumers may decrease the consumption of goods, such as automobiles, that are complementary with the use of petroleum products.

The result is less aggregate demand, leading to falling prices and output. Also, foreign oil producers tend to save more than U.S. consumers, which results in downward pressure on interest rates. Thus, the anticipated impacts of a reduction of aggregate demand produces results that may not agree with the historical record, except for the reduction in output.

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[3]Steven Brown, Mine K. Yucel and John Thompson, "Business Cycles: The Role of Energy Prices", in *Encyclopedia of Energy*, C.J. Cleveland, ed., New York, Academic Press, 2004. A review article is available as a FRB of Dallas Working Paper, Number 0304, 2006. The chart is found on page 3 of the working paper.

[4]These reactions to higher oil prices are spelled out in Lutz Kilian, "The Economic Effects of Energy Price Shocks," *Journal of Economic Literature*, Vol. 46, 2008, pp. 871–909 -- see page 881.

The third item in the table, "Monetary Shocks," has a long and contentious history in the literature on oil price shocks. Some of the early dissenters from the oil-shock theory of post-WWII recessions have argued that it has been monetary policy rather than changes in the price of oil that has caused the downturns in output that seem follow most episodes of oil price hikes. A seminal paper that argues this point is the 1997 paper by Bernanke, et al. in which they conclude that the recessions that followed the 1973, 1979-80, and 1990 oil price increases could be almost entirely attributable to monetary policy and not oil shocks.[5] Their argument is that it was restrictive monetary policy that caused interest rates to increase and aggregate demand to fall leading, to the recessions, and that the oil price increases had little influence on the downturn. While two of the three highlighted variables in this theoretical construct of events do move in the same direction as the historical record, a monetary tightening would tend to reduce prices, not increase them.

The final item in the chart, the "Real Balance Effect" is an argument that was offered as a possible explanation as to why seemingly small oil price changes had such large impacts on the economy. Briefly, it was argued that increasing energy prices led to increased demand for money to restore a desired level of portfolio liquidity. Unless monetary authorities recognized this increased demand for funds and increased the money supply, the increased demand for money would drive up interest rates, reduce aggregate demand, and lead to a decrease in output. Table I-1 shows that a "Real Balance Effect" would have the same impact as a tightening of monetary policy. As in the case of a tightening of monetary policy, the resulting impacts parallel the historical record in only two of the three variables – interest rates and output.

The above approaches to accounting for energy price shocks make the standard assumptions regarding market competitiveness. However, there have been other approaches to explaining the outsized impact of energy price shocks that rely on market imperfections. Most of these approaches involve imperfections on the supply side of the economy and, therefore, would create impacts that mirror the historical record.

For example, Rotemberg and Woodford assume collusive pricing powers that allow mark-ups to the original energy-price spike throughout the manufacturing chain.[6] Their theoretical model can duplicate the impact on output found in the data, but their assumption of such widespread collusive power is problematic. Another widely cited paper by Finn accepts perfect competition, but adds to the increasing cost of energy inputs large increases in the cost of capital depreciation as high energy costs render energy-using capital non-productive.[7] Reductions in capital utilization reduce efficiency and decrease output. Models of this type are called "putty-clay" meaning that once decisions are made to install a certain type of capital technology – the "putty" stage, the

[5]Ben S. Bernanke, Mark Gertler, and Mark Watson, "Systematic Monetary Policy and the Effects of Oil Price Shocks," *Brookings Papers on Economic Activity*, Issue 1, pp. 91–142, 1997.
[6]See J.J. Rotemberg and M. Woodford, "Imperfect Competition and the Effects of Energy Price Increases on Economic Activity," *Journal of Money, Credit and Banking*, Vol. 28, 1996, pp. 549-577.
[7]See Mary G. Finn, "Perfect Competition and the Effects of Energy Price Increases on Economic Activity," *Journal of Money, Credit and Banking*, Vol. 32, 2000, pp. 400-416.

decisions are not then alterable – the "clay" stage -- despite changes in the operating environment (e.g., changing energy prices).

Other research has considered friction in labor markets to account for the size of downturns following energy price spikes. For example, energy price increases have exceptionally large adverse impacts on the transportation industry.[8] Idled workers (and capital) in the industry cannot be shifted easily to other employment owing to structural issues and, perhaps, sticky wages. This increase in unemployed resources owing to allocative inefficiencies magnifies the direct, aggregate effects of the energy price change. Hamilton estimated that the downturn in the auto industry during the 1980 and 1990-91 recessions was enough to push the economy into recession from what might well have been periods of "sluggish" growth.[9]

Asymmetric Impact

Aside from the issues discussed above, other controversies have characterized the research on the energy shock-output relationship. One such issue is the apparent asymmetry of energy shocks – they apparently have a greater negative impact when prices increase than positive impacts when prices decline. This issue came to the forefront during the 1980's when a decline in energy prices failed to result in an acceleration in growth similar to the decline in growth after the 1970's energy price increases.

One of the first analysts to rigorously investigate this anomaly was K. A. Mork[10] who found that when he introduced separate oil price variables for price increases and price declines, the price increases had more of an effect than the price decreases. Other researchers found similar results, although the classic aggregate supply-aggregate demand model predicts that there should be no difference in response whether the oil price shock is positive or negative. Several explanations have been suggested for the anomaly, including an asymmetry of the price pass-through of oil price changes to retail product (e.g., gasoline) price changes – price increases are passed through more rapidly than are decreases.[11] Another possibility suggested was that monetary policy responses to oil price increases were different than the responses to an oil price decreases, and that it was this policy asymmetry that caused the apparent difference in positive versus negative energy price changes.[12]

[8]See, for example, Timothy F. Bresnahan and Valerie A. Ramey, "Segment Shifts and Capacity Utilization in the U.S Automobile Industry," *American Economic Review*, 83 (2), 1993, pp. 213–18.
[9]James D. Hamilton, "Causes and Consequences of the Oil Shock of 2007-08", presented at the Brookings Panel on Economic Activity, April 2009; James D. Hamilton, Department of Economics, UC San Diego, Working Paper, 2009, p. 29.
[10]See Knut A. Mork, "Business Cycles and the Oil Market," *Energy Journal*, Vol. 15, No. 4, Special Issue (1994): pp. 15-38.
[11]Balke, Nathan S., et. al., "Oil Price Shocks and the U.S. Economy: Where Does the Asymmetry Originate?" Federal Reserve Bank of Dallas, Working Paper No. 9911, 1999.
[12]See John Tatum, "Are the Macroeconomic Effects of Oil-Price Changes Symmetric?" *Carnegie-Rochester Conference Series on Public Policy*, Volume 28, Spring 1988, pp. 325-368.

Another possible explanation relied on the possibility that the same allocative frictions that were identified as the cause of the size of oil price shock impacts could be responsible for the asymmetrical effects. The reasoning is that although the aggregate impact of a price decrease would shift the supply curve to the right resulting in increased output, the same allocative adjustment problems that accompany price increases would be present during price decreases, operating to slow growth and partially offset any positive aggregate effect. Finally, Lutz Kilian, who generally disputes the argument that energy price shocks are responsible for shifts in economic activity, offers the explanation that the apparent asymmetry was caused by policy changes (e.g., the 1986 Tax Reform Act) and not differences in the way that oil prices changes impact the economy.[13]

A Weakening Relationship

Aside from the possible explanation discussed above, some analysts contend that the reason for the weak response of output to energy prices decreases during the 1980's was caused by a general weakening of the relationship, that the structure of the economy had changed. Brown, et al. offers several possible reasons for the diminishing impact of oil price changes. They discuss the role of a fall in the energy-to-GDP ratio, the growing experience with oil price changes (In the 1970's the changes were a "shock," but by the 1980's and 1990's oil price changes were not so novel.), the fact that strong productivity gains in the late 1990's tended to hide the oil price-output relationship and, finally, that the increases in energy prices in the 1990's came from an increase in aggregate demand and not from a decrease in aggregate supply.[14,15]

The last explanation became popular during the run-up of energy prices in the late 2000's, prior to the onset of the financial crisis in 2008. There were a number of articles and commentaries pointing to the fact that despite increasing oil prices, the economy continued to grow. Perhaps most notable among these papers is one by William Norhaus, in which he offered several of the factors discussed above as to why higher oil prices failed to derail the economic expansion.[16] Following the financial crises of the summer and fall of 2008 and the subsequent economic implosion, most economic commentary focused on the role of the financial sector as the primary cause of the sharp downturn. There were those, however, who argued that the run-up in oil prices was a significant factor behind the recession, pointing out that the economy began to slow and that the NBER marked the start of the recession in December 2007 -- months before the financial crises caused the bottom to fall out.[17]

[13]See Kilian, op.cit., p. 891.
[14]See Brown, et al., op.cit., p. 14.
[15]In addition to possible structural changes as explanations for the reduction of the force of oil price shocks, several analysts considered other, more technical, reasons including the structure of equations used to estimate impacts and the precise definition of what an "oil price shock" really was. See Jones, et al., op. cit. p. 10, for a discussion if these issues.
[16]William D. Nordhaus, "Who's Afraid of a Big Bad Oil Shock?" *Brookings Papers on Economic Activity*, Issue 2 (Fall 2007), p. 219-240.
[17]See James D. Hamilton, "Causes and Consequences of the Oil Shock of 2007-08," presented at the Brookings Panel on Economic Activity, Department of Economics, UC San Diego, April 2009. Also, see

What is the Size of the Relationship?

Not surprisingly, given the dozens of studies that have examined the relationship between oil price shocks and the economy, there are numerous estimates of the size of the response in GDP to a one percent change in the price of oil or energy. One generalization that can be made from the results of these studies is that those estimates that are the result of more simple time-series estimates of the impact of oil and energy prices on the macroeconomy tend to be much larger than estimates made using large disaggregated macroeconomic models of the economy. In the former case, estimates tend to range from around 2.5 percent to up to 11 percent in an estimate by Hamilton.[18]

In contrast, disaggregated models, such as the models of the IMF, OECD and Federal Reserve, tend to derive estimates that are much smaller, in the range of 0.2 percent to 1.0 percent. Jones, et al. explains the difference by pointing out that much of the overall impact on GDP that results from an energy price shock comes as a result of the friction in inter-sectoral resource allocation, and the large, disaggregated models are not able to gauge these effects.[19]

I.B. Long-Run Impacts

At the beginning of Section I.A. in the discussion of the impact of changes in energy prices in the short run, energy, E, was introduced as an explicit factor -- along with labor and capital -- in the production function that described the structure of the aggregate supply curve. In the mainstream theories of long-term economic growth, energy plays no such role. Rather, growth is theorized as being a function of labor (population), capital, and technological change.[20]

A seminal article by Robert Solow in 1956 marked the beginning of mainstream neoclassical growth theory.[21] Although his work on the issue of economic growth earned Solow the Nobel Prize, the construct that he used to describe growth $Q = f(L,K)$ had a major flaw in that the two explicit exogenous variables, labor and capital, explained little of the actual growth in the U.S. economy. A large "Solow residual," introduced as an exogenous unexplained variable accounted for most of the growth in per capita income. Since this residual, that Solow identified as "technological progress"

Joe Cortright, "Driven to the Brink: How the Gas Price Spike Popped the Housing Bubble and Devalued the Suburbs", White Paper, CEOs for Cities, May 2008.

[18]See James D. Hamilton, "What is an Oil Shock?" *Journal of Econometrics*, v.113, April 2003, pp. 363 – 398. Jones, et al, op.cit, p. 12, has a discussion of some of the results of these estimates.

[19]See Donald W. Jones, et al, op.cit, p. 12. Also see Hilliard G. Huntington, "The Economic Consequences of Higher Oil Prices," final report for the U.S. Department of Energy, EMF SR 9, October 2005.

[20]This brief introduction and summary of mainstream economic growth theory draws heavily on the review of the subject by Robert Ayres. See Robert U. Ayres, "Lecture 5: Economic Growth (and Cheap Oil)", presentation made at the Lisbon, Portugal 2005 meeting of the ASPO Fourth International Workshop on Oil and Gas Depletion.

[21]See Robert M. Solow, "A Contribution to the Theory of Economic Growth, *Quarterly Journal of Economics*, vol. 70, 1956, pp. 65-94.

was, as noted, unexplained, or exogenous, this class of models came to be known as exogenous growth models.

During the 1980s, Pail Romer, Robert Lucas, and others initiated a new phase of growth theory that has come to be known as "modern" or "endogenous" growth theory. Their models were structured to include variables such as research and development and human capital to explain the sources of Solow's "technological progress."[22] While these new approaches have advanced growth theory, they have not served to answer some of the fundamental questions about growth, such as why different economies grow at different rates. Robert Ayres notes that while the neoclassical endogenous growth models have "interesting features," he also states "......all of the so-called endogenous growth models share a fundamental drawback: They are and are likely to remain essentially theoretical because none of the proposed choices of core variables (knowledge, human capital, etc.) is readily quantified, and the obvious proxies (like education expenditure, years of schooling, and R&D spending) do not explain growth."[23]

Growth Theory and Energy

In a 2002 paper Ayres and his colleague Benjamin Warr asked the question "Why should capital services be treated as a "factor of production" while the role of energy services . . . . .is widely ignored or minimized?"[24] Ayres and Warr then proceeded to discuss what they see as the two primary reasons behind the fact that mainstream neoclassical economics ignores energy (and other resource) inputs when creating models of economic growth. First, neoclassical theory assumes that the productivity of a factor of production must be proportional to that factor's share of national income. Labor and capital receive, by far, the largest shares of national income, with payments to energy receiving very little. Theory concludes then that energy must be a negligible factor of production and can be ignored.

A second reason that neoclassical economists ignore energy is because of the problem of causation. Correlation between energy use and growth may be the result of growth leading to more energy use and not because energy use results in growth. [25] The standard mainstream model, such as the EIA NEMS model, makes just this assumption in its forecasts. That is, NEMS assumes that growth in the macroeconomy

[22]Fairly non-technical reviews of the development of endogenous growth theory can be found in Robert W. Arnold, "Modeling Long-Run Economic Growth", Technical Paper Series No. 2003-4, Congressional Budget Office, Washington D.C. June 2003; Lars Weber, "Understanding Recent Developments in Growth Theory", Brandenburg University of Technology Cottbus, 2007; and Joseph Cortright, "New Growth Theory, Technology and Learning: A Practitioners' Guide," *Reviews of Economic Development Literature and Practice*, No. 4, report done under contract (99-07-13801) for the U.S. Economic Development Administration by Impresa, Inc. 1424 NE Knott St, Portland, Oregon.
[23] See Ayres, op.cit, p. 8.
[24]See Robert U. Ayres and Benjamin Warr, "The Economic Growth Models and the Role of Physical Resources,", INSEAD Working Paper, No. 2002/53/EPS/CMER, 2002, p. 4.
[25] Ayres and Warr, op.cit., pp. 4-6.

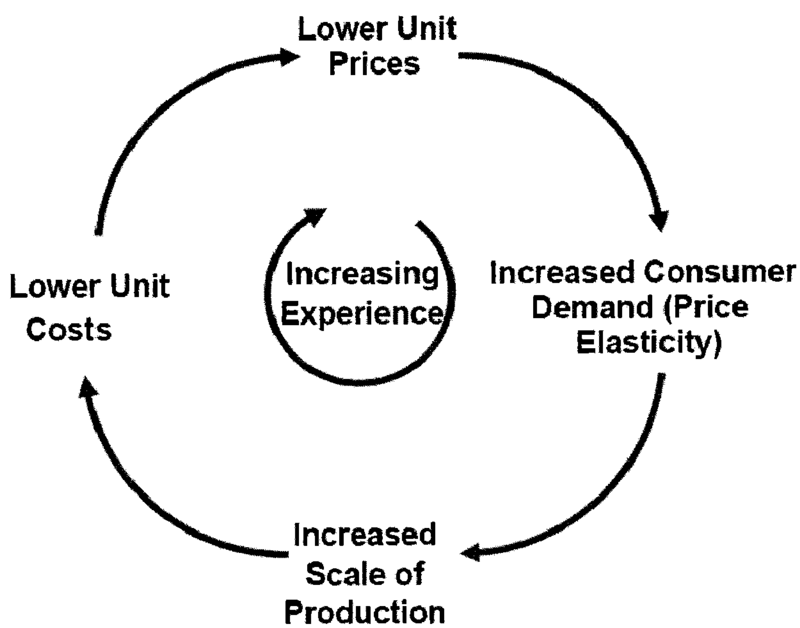
is determined by exogenous factors such as population growth, technology growth, and monetary, and fiscal policies. Demand for energy products is the result.[26]

As an alternative approach, Ayres and others recommend that growth models include an energy variable as an explicit input. They contend that energy is an example of an "engine of growth" that provides positive feedback cycles in the growth process as depicted in the so-called Salter cycle – see Figure II-1.[27] Increases in low-cost energy translate into lower prices for products and services, and this leads to greater demand. The lower energy prices result from new discoveries, economies of scale, and technical progress in the efficiency of energy use. In other words, as in the case of capital, energy is a factor of production and should be treated as such.[28]

Models that have included energy variables in the standard neoclassical production function explain most of the growth left unexplained in the standard two-variable Solow mode.[29]

[26]See U.S. Energy Information Administration, "The National Energy Modeling System: An Overview 2003", report # DOE/EIA-0581 (2003).
[27]Ayres, op.cit., p. 26.
[28]Ayres, ibid., p. 4.
[29]Ayres, ibid. p.4. notes the work of Bruce Hannon and John Joyce, "Energy and Technical Progress", *Energy*, vol. 6, pp. 187-195, 1981; Reiner Kummel, "Energy, Environment and Industrial Growth," in *The Economic Theory of natural Resources*, Physica-Verlag, Wuerzberg, Germany, 1982; Cutler J. Cleveland, et al., "Energy and the U.S. Economy: A Biophysical Perspective," *Science*, v. 255, pp. 890-97, 1984; and others.

Figure II-1
Representation of the Slater Cycle



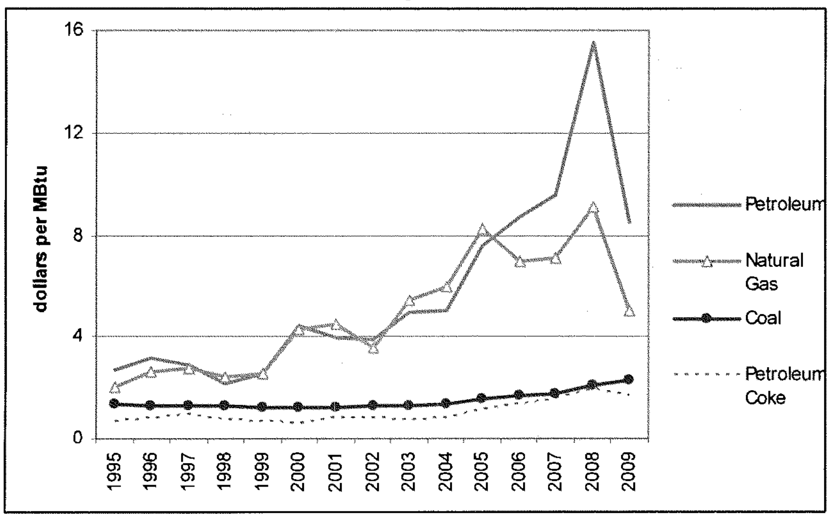
Source: Robert U. Ayres, "Lecture 5: Economic Growth (And Cheap Oil)," INSEAD, Boulevard de Constance, F-77305 Fontainebleau Cedex, France

II. COSTS OF ELECTRICITY GENERATION OPTIONS

II.A. Fuel Costs for Electricity Generation

For decades, coal has been – and remains -- the least costly and least price-volatile fuel for electricity generation. As shown in Figure II-1, coal costs to the electricity generation sector have consistently been much lower and less volatile than competing fuels.

Figure II-1
Electric Power Industry Fuel Costs, 1995 - 2009



Source: U.S. Energy Information Administration, *Receipts, Average Cost, and Quantity of Fossil Fuels Through May 2009*; and MISI, 2009.

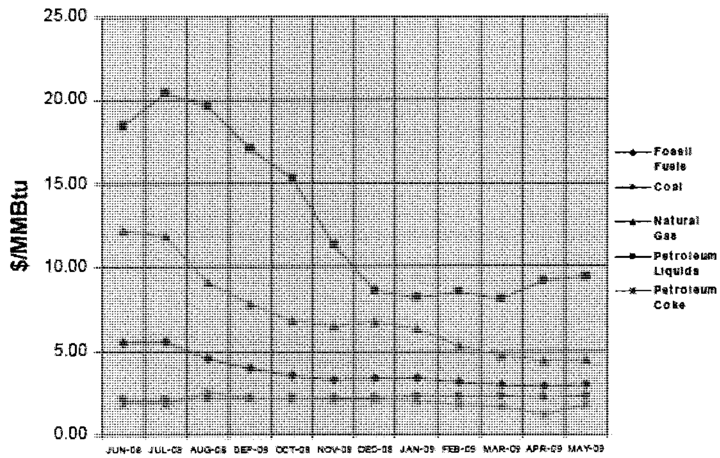
More recently, as shown in Figure II-2, EIA found that in May 2009, the price of coal, petroleum, and natural gas to electricity generators increased slightly from the previous month.[30] Nevertheless, the salient point is that coal remains orders of magnitude cheaper than the competing fuels:

- The average price paid for coal in May 2009 was $2.25 per MMBtu, up 0.9 percent from the price paid in April. It was 9.8 percent higher when compared with the May 2008 price of $2.05 per MMBtu.

[30]U.S. Energy Information Administration, *Electric Power Monthly*, August 2009.

- The average price paid for petroleum liquids increased from $9.15 per MMBtu in April 2009 to $9.41 in May. This was a 2.8-percent increase from April and a 46.3-percent decrease from May 2008.
- The average price paid for natural gas by electricity generators in May was $4.46 per MMBtu, a 1.4-percent increase from the April 2009 level of $4.40 and a 58.3-percent decrease from May 2008.

Figure II-2
Electric Power Industry Fuel Costs, June 2008 through May 2009



Source: U.S. Energy Information Administration, *Electric Power Monthly*, August 2009

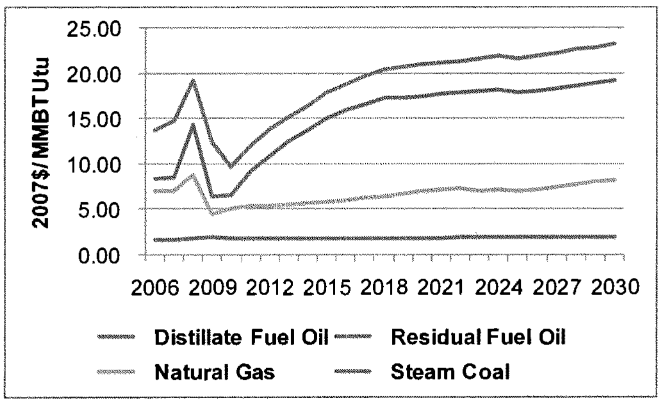
The overall price paid by electricity generating plants for fossil fuels was $2.95 per MMBtu in May 2009, a 3.5-percent increase from April 2009 and a 32.0 percent decrease from May 2008. Year-to-date (January through May) 2009 prices compared to the same period last year were up 15.9 percent for coal, down 43.8 percent for petroleum liquids, and down 45.7 percent for natural gas.

Further, EIA forecasts that coal fuel prices for electricity generation will remain low and that their price advantage will increase. As shown in Figure II-3, EIA forecasts that:

- In 2015, coal costs will be 10.6 percent of those of distillate fuel oil, 12.5 percent of those of residual fuel oil, and 32.4 percent of those of natural gas

- In 2020, coal costs will be 9.3 percent of those of distillate fuel oil, 11.2 percent of those of residual fuel oil, and 27.9 percent of those of natural gas
- In 2030, coal costs will be 8.8 percent of those of distillate fuel oil, 10.6 percent of those of residual fuel oil, and 24.4 percent of those of natural gas

Figure II-3
EIA forecast of Electricity Generation Fuel Prices



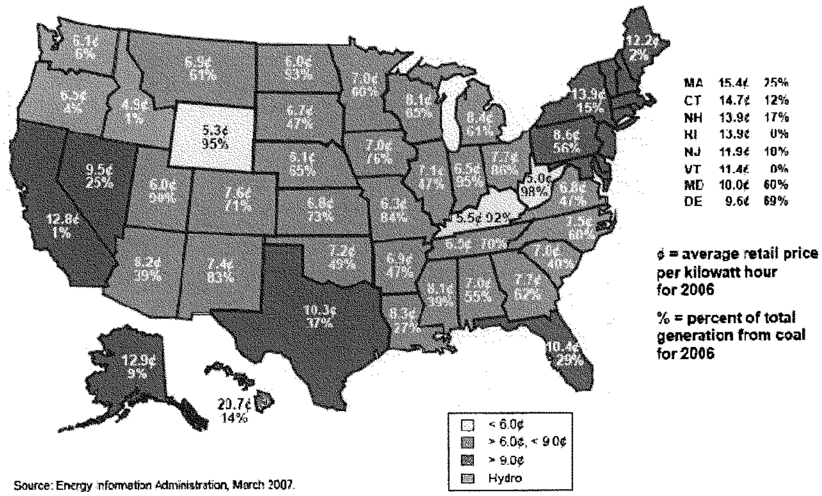
Source: U.S. Energy Information Administration, 2009.

II.B. Coal Generation and State Electricity Rates

Coal-fueled power plants produce over 50 percent of U.S. electricity, and 23 of the 25 power plants in the U.S. that have the lowest operating costs (and therefore provide power to their consumers at the lowest prices) are powered by coal. In states where coal is used for the highest percentage fuel mix, electricity production costs and rates are the lowest. Figure II-4 shows that, in general, states that use coal to generate most of their electricity have electric rates that are only about half as large as those of other states.

Figure II-4
States that Rely on Coal Have Low-Cost Electricity

16 States: 21% from Coal & 12.7 Cents/kWh Average
31 States: 65% from Coal & 7.0 Cents/kWh Average

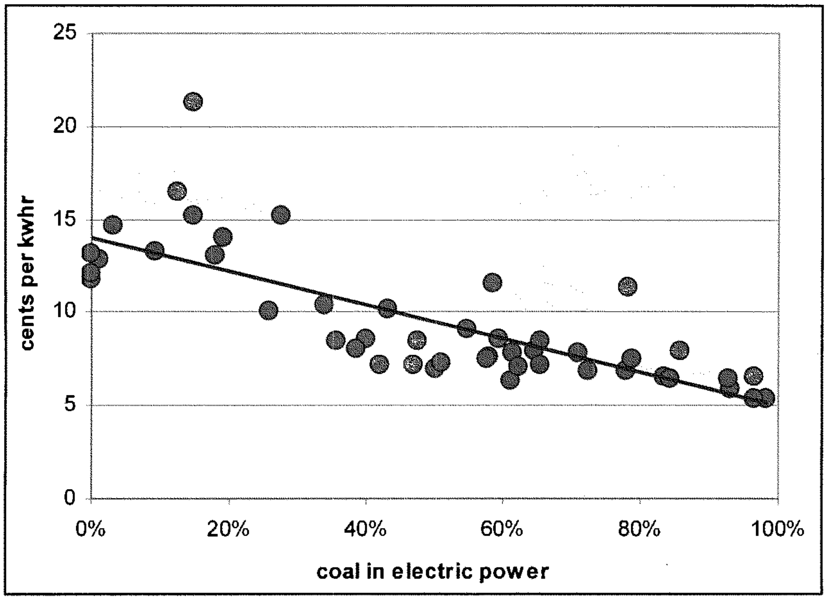


Source: Energy Information Administration, March 2007.

The relationship between coal generation and electricity costs is further illustrated in Figure II-5, which shows the correlation between state average electricity prices and percent of that state's electricity provided by coal.[31] This figure illustrates that, in general, there is a strong negative relationship between electricity prices and the use of coal to generate electricity: The higher percentage of coal used to generate electricity, the lower the electricity rate.

[31]All four states classified by EIA as "Primarily Hydroelectric" have been excluded from Figure II-5 since their low electricity rates are attributable to cheap hydroelectric power and not necessarily coal. These states are Idaho, Washington, Oregon, and South Dakota.

Figure II-5
The Relationship of State Average Electricity Prices and Coal Fuel Inputs - 2007



Source: U.S. Energy Information Administration, *Selected Electric Industry Summary Statistics by State* and *Electric Power Sector Consumption Estimates*; and Management Information Services, Inc., 2009.

II.C. LCOE Plant Costs

The levelized cost of electricity (LCOE) is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt, accrued interest on initial project expenses, and the payment of an acceptable return to investors. LCOE is comprised of three components: Capital charge, operation and maintenance costs, and fuel costs. Capital cost is generally the largest component of LCOE.

Levelized costs represent the present value of the total cost of building and operating a generating plant over its financial life, converted to equal annual payments and amortized over expected annual generation from an assumed duty cycle. The key factors contributing to levelized costs include the cost of constructing the plant, the time required to construct the plant, the non-fuel costs of operating the plant, the fuel costs, the cost of financing, and the utilization of the plant. The availability of various incentives including state or federal tax credits can also impact these costs.[32]

Levelized costs can be useful when comparing different technology options to satisfy a given duty cycle requirement. For example, LCOE could be used to determine the lowest cost new capacity available to satisfy a need for baseload power that would be expected to operate at a 70 percent capacity factor or higher.

Levelized costs for different technologies can be evaluated using appropriate capacity factors, which generally correspond to the maximum availability of each technology.[33] However, it should be noted that a technology such as a conventional combined cycle turbine that appears relatively expensive at its maximum capacity factor may be the most attractive option when evaluated at a lower capacity factor that would be associated with an intermediate load duty cycle. Simple combustion turbines (conventional or advanced technology) are typically used for peak load duty cycles, and are thus evaluated at a 30 percent capacity factor. The duty cycle for intermittent renewable resources of wind and solar is not operator controlled, but dependent on the weather or solar cycle. The availability of wind or solar will not necessarily correspond to operator dispatched duty cycles and, as a result, their levelized costs are not directly comparable to those for other technologies, even where the average annual capacity factor may be similar. In addition, intermittent technologies do not provide the same contribution to system reliability as dispatched resources, and may require additional system investment to achieve a desired level of reliability – see the discussion in Section II-D.

Reliable, comparable, consistent LCOE estimates for existing generation options are difficult to obtain. For example, EIA AEO documents do not provide these because these reports are forecasts and EIA only estimates projected costs for building new capacity.[34]

The Brattle Group has estimated the current LCOE costs of standard baseload options, and these are summarized in Table II-1. Cost estimates range between 7.8 ¢/kWh for coal (super critical) to 11.6 ¢/kWh for wind with gas backup.

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[32]EIA, "Levelized Cost of New Generation Resources from the Annual Energy Outlook 2009," 2009.
[33]While there are no definitive utilization breakpoints, baseload plants are facilities that operate almost continuously, generally at annual utilization rates of 70 percent or higher. Intermediate load plants are facilities that operate less frequently than baseload plants, generally at annual utilization rates between 25 and 70 percent. Peaking plants are facilities that only run when the demand for electricity is very high, generally at annual utilization rates less than 25 percent.
[34]EIA staff communications with MISI, August and September 2009.

Table II-1
Estimated Levelized Costs per MWH

Type of Plant	Cost of Capital	Fixed O+M	Fuel	Variable O+M	CO2 Price	CO2 Transport & Storage	Total
Coal (Super Critical)	39.09	5.56	16.80	4.00	12.79	0.00	$78.24
Coal (IGCC)	54.14	6.97	19.60	5.00	14.48	0.00	$100.20
Coal (IGCC with Sequestration)	71.38	8.17	21.00	6.00	1.58	4.46	$112.59
Natural Gas (Combined Cycle)	13.43	2.17	56.00	1.50	6.25	0.00	$79.34
Natural Gas (Combined Cycle)	13.43	2.17	70.00	1.50	6.25	0.00	$93.34
Wind with gas back-up	56.65	2.93	51.00	1.10	4.06		$115.74
Nuclear	88.85	11.18	6.31	4.48	0.00	0.00	$110.82

Source: The Brattle Group, 2009.

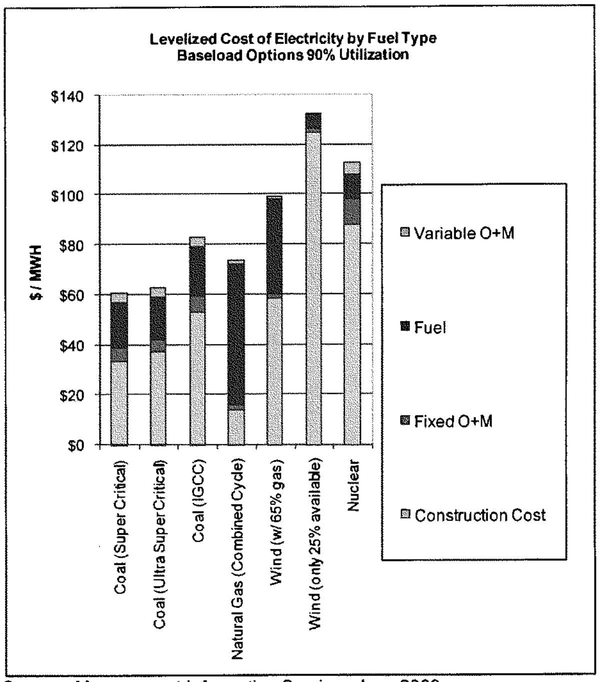
A large U.S. energy company has estimated the current LCOE costs of major baseload options and has made these data available to MISI. These are summarized in Table II-2 and Figure II-1, and indicate that costs range from 6.1 ¢/kWh for coal (super critical) to 13.3 ¢/kWh for wind without gas backup

Table II-2
Estimated Levelized Costs per MWH

	Construction Cost	Fixed O+M	Fuel	Variable O+M	Temp and Perm Waste Disposal	Total
Coal (Super Critical)	33.72	5.07	18.20	4.00	0.00	61.00
Coal (Ultra Super Critical)	37.10	5.07	16.80	4.00	0.00	62.97
Coal (IGCC)	53.11	6.34	19.60	4.00	0.00	83.06
Natural Gas (Combined Cycle)	13.90	2.28	56.00	1.50	0.00	73.69
Wind (w/ 65% gas)	58.32	1.90	38.15	1.10	0.00	99.47
Wind (only 25% available)	124.82	1.75	5.50	0.50	0.00	132.57
Nuclear	88.20	10.15	10.00	4.86	0.00	113.21

Source: Management Information Services, Inc., 2009.

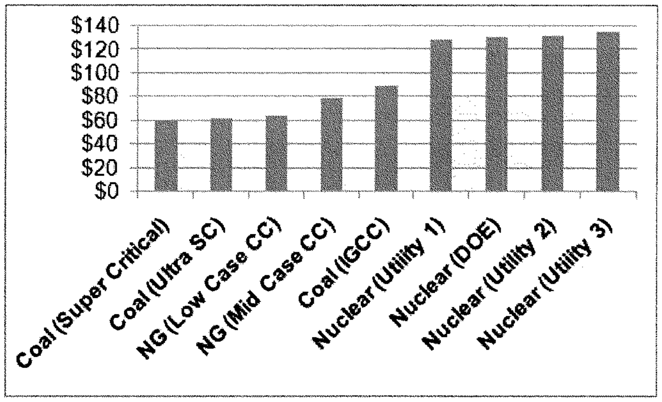
Figure II-1



Source: Management Information Services, Inc., 2009.

One of the largest U.S. combined electric and natural gas utilities conducted a detailed analysis for planning purposes of the current LCOE costs of baseload options at several utilities and provided these estimates to MISI. As shown in Figure II-2, these current LCOE costs range from 6¢/kWh for coal super critical to 13.5¢/kWh for wind.

Figure II-2
Estimated Levelized Costs per MWH

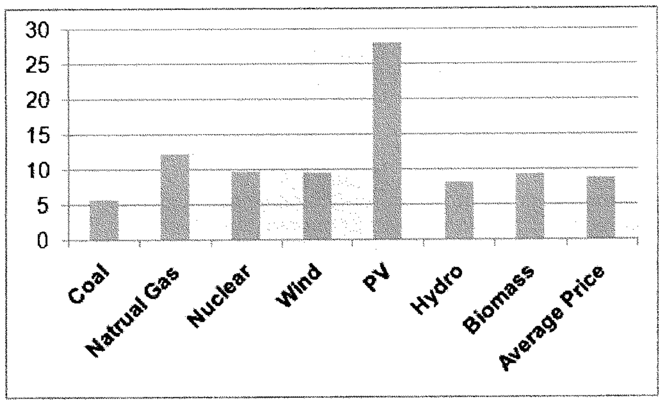


Source: Management Information Services, Inc., 2009.

Pennsylvania State University estimated 2005 LCOE costs in Pennsylvania,[35] and these are shown in Figure II-3

[35]Rose, Adam, and Dan Wei, *The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015,* report prepared for the Center for Energy and Economic Development, Inc., Alexandria, Virginia, the Pennsylvania State University, July 2006.

Figure II-3
Estimated 2005 Pennsylvania Levelized Costs per MWH
¢/kWh (2007 dollars)



Source: Pennsylvania State University

In 2007, MIT conducted a comprehensive analysis of coal generation costs and reviewed and critically analyzed seven coal technology design and cost studies.[36] These studies estimated the required capital cost and LCOE for current coal-based generating technologies. The capital costs for each study were developed independently and thus exhibited considerable variation. Further, the financial and operating assumptions that were used to calculate the LCOE varied from study to study, which also added variability to the LCOE.[37]

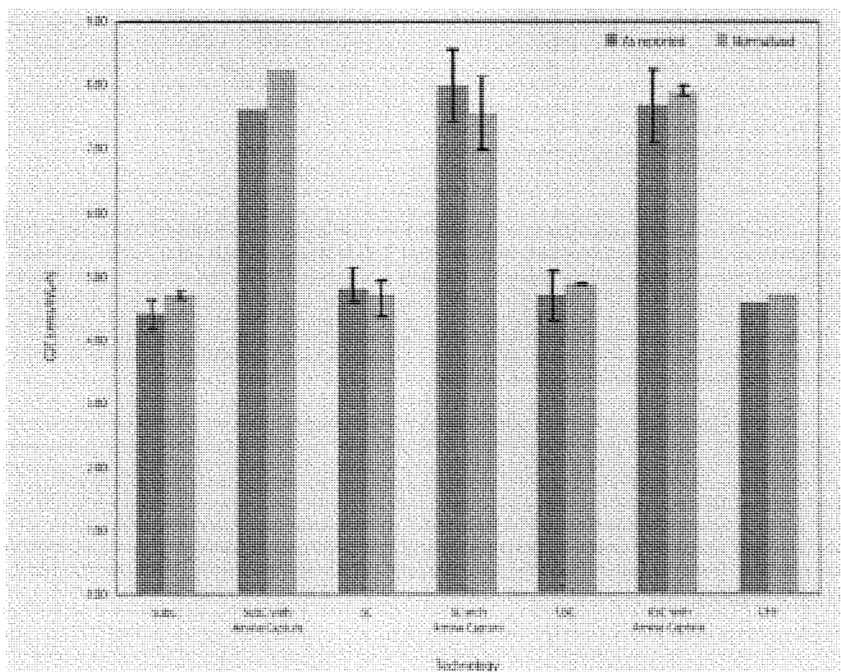
To allow comparison of capital costs, O&M costs, and the LCOE among these studies, each was reevaluated using a common set of operating and economic parameters. In addition to comparable economic parameters, MIT used a capacity factor of 85 percent, and a fuel cost of $1.50/million Btu for the PC and IGCC cases, and $1.00/million Btu for the CFB case. Each study was adjusted to a 2005 year cost basis. The results of the re-evaluation using the normalized economic and operating parameters are summarized in Figures II-4 and II-5 for the PC and CFB, and the IGCC cases, respectively.

[36]Massachusetts Institute of Technology, *The Future of Nuclear Power*, 2003
[37]Several studies that were on a substantially different basis or fell well outside the range expected were not included in the MIT analysis because there was no adequate way to effectively evaluate them.

Converting the 2005 dollar data in these figures to 2007 dollars indicates that:

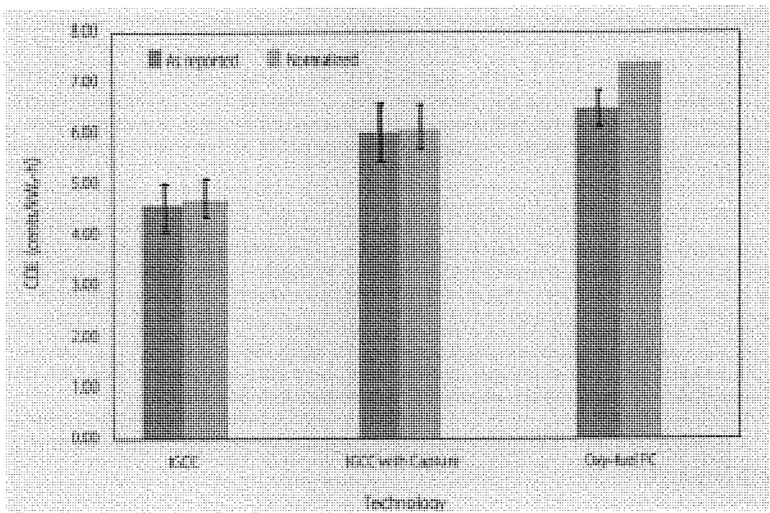
- The LCOEs for air-driven technologies range from 4.8¢/kWh to 5.1 ¢/kWh for subcritical and from 8¢/kWh to 9¢/kWh for subcritical with amine capture
- The LCOEs for Oxygen-Blown technologies range from 5¢/kWh to 5.1¢/kWh for IGCC and from 7¢/kWh to 7.8¢/kWh for oxy-fuel with PC

Figure II-4
LCOEs From Design Studies of Air-Driven Generating Technologies – "as Reported" and for Normalized Economic and Operating Parameters
(2005 dollars)



Source: Massachusetts Institute of Technology, 2003.

Figure II-5
LCOEs From Design Studies of Oxygen-Blown Generating Technologies – "as Reported" and for Normalized Economic and Operating Parameters
(2005 dollars)



Source: Massachusetts Institute of Technology, 2003.

In 2003, MIT conducted a comprehensive analysis of nuclear power costs compared to other baseload options, and in 2009 these findings were revised and updated.[38] With regard to nuclear power, MIT found that, while there has been some progress since 2003, increased deployment of nuclear power has been slow both in the United States and globally, in relation to the illustrative scenario examined in the 2003 report. While the intent to build new plants has been made public in several countries, there are currently few firm commitments to construction projects outside of Asia, in particular China, India, and Korea. Even if all the announced plans for new nuclear power plant construction are realized, the total will be well behind that needed for reaching a thousand gigawatts of new capacity worldwide by 2050. In the U.S., only one shutdown reactor has been refurbished and restarted and one previously ordered,

[38]Massachusetts Institute of Technology, *The Future of Nuclear Power,* 2003; Massachusetts Institute of Technology, *Update of the MIT 2003 Future of Nuclear Power Study,* 2009. See the discussion in Roger H. Bezdek, "Nuclear Power Economics and Prospects in the USA," *International Journal of Nuclear Governance, Economy and Ecology*, Vol. 2, No. 3, (June 2009), pp 262- 280.

but never completed reactor, is being completed. No new nuclear units have started construction.

The 2003 report found that "In deregulated markets, nuclear power is not now cost competitive with coal and natural gas. However, plausible reductions by industry in capital cost, operation and maintenance costs and construction time could reduce the gap. Carbon emission credits, if enacted by government, can give nuclear power a cost advantage." The 2009 MIT update reported that the situation essentially remained the same. While the U.S. nuclear industry has continued to demonstrate improved operating performance, there remains significant uncertainty about the capital costs and the cost of its financing, which are the main components of the cost of electricity from new nuclear plants.

MIT found that since 2003, construction costs for all types of large-scale engineered projects have escalated dramatically. The estimated cost of constructing a nuclear power plant has increased at a rate of 15 percent per year heading into the current economic downturn. This is based both on the cost of actual builds in Japan and Korea and on the projected cost of new plants planned for in the U.S. Capital costs for both coal and natural gas have increased as well, although not by as much. The costs of natural gas and coal that peaked sharply is now receding. Taken together, these escalating costs leave the situation close to where it was in 2003.[39]

Table II-3 updates the cost estimates presented in the 2003 study, and Figure II-4 shows these estimates in 2007 dollars.

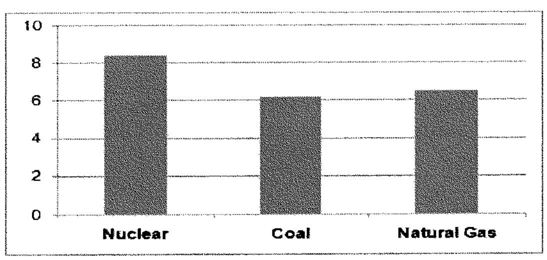
[39]The 2003 study concluded that "The sober warning is that if more is not done, nuclear power will diminish as a practical and timely option for deployment at a scale that would constitute a material contribution to climate change risk mitigation."

Table II-3
Estimated Costs of Electricity Generation Alternatives

			LCOE		
	Overnight Cost	Fuel Cost	Base Case	w/ carbon charge $25/ tCO_2	w/ same cost of capital
	$/kW	$/mmBtu	¢/kWh	¢/kWh	¢/kWh
	[A]	[B]	[C]	[D]	[E]
MIT (2003)					
$2002					
[1] Nuclear	2,000	0.47	6.7		5.5
[2] Coal	1,300	1.20	4.3	6.4	
[3] Gas	500	3.50	4.1	5.1	
Update					
$2007					
[4] Nuclear	4,000	0.67	8.4		6.6
[5] Coal	2,300	2.60	6.2	8.3	
[6] Gas	850	7.00	6.5	7.4	

Source: Massachusetts Institute of Technology, 2009.

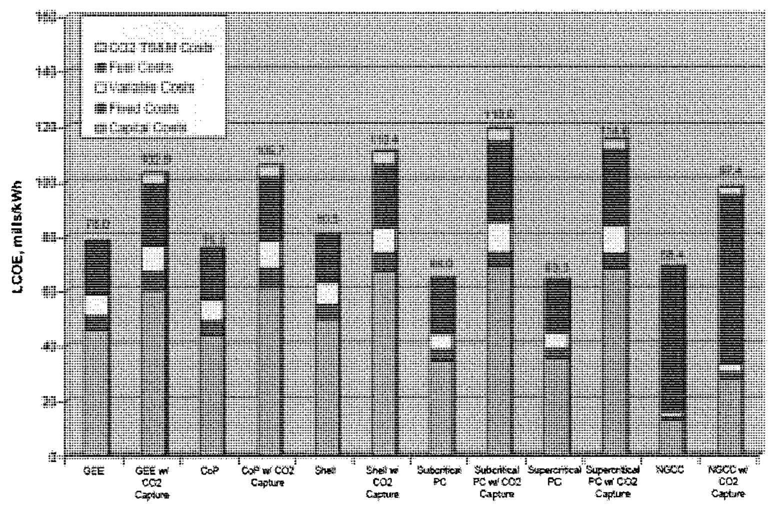
Figure II-6
Estimated Costs of Electricity Generation Alternatives
¢/kWh (2007 dollars)



Source: Massachusetts Institute of Technology, and Management Information Services, 2009.

In 2007, NETL estimated LCOEs for fossil energy power systems, specifically IGCC, PC, and NGCC plants, using a consistent technical and economic approach that accurately reflected market conditions for plants starting operation in 2010.[40] These are shown in Figure II-7.

Figure II-7
LCOE by Cost Component



Source: National Energy Technology Laboratory, 2007.

EIA estimated levelized costs of new generation resources for AEO, 2009. Its reports are forecasts, and EIA only has projected costs for building new capacity. It does not have estimates for 2007 or 2010, since a new plant could not be licensed and built in that time.[41]

While EIA does not publish detailed LCOE estimates as part of its AEO studies, it did provide MISI with unpublished forecasts of these costs for 2020 and 2030. Table II-4 provides the average national levelized costs for the generating technologies represented in NEMS as configured for the updated *Annual Energy Outlook 2009* reference case.[42] In this table, EIA contends that the LCOE for each technology is

[40]Research and Development Solutions, LLC, and Parsons Corporation, *Cost and Performance Baseline for Fossil Energy Plants*, report prepared for the National Energy Technology Laboratory, DOE/NETL-2007/1281, August 2007.
[41]EIA staff communications with MISI, August and September 2009.
[42]Provided by EIA staff to MISI in August 2009. The original full report and updated reference case are available at http://www.eia.doe.gov/oiaf/aeo/index.html.

estimated based on appropriate capacity factors for each technology. The costs shown in the table are national averages; however, there is significant local variation in costs based on local labor markets and the cost and availability of fuel or energy resources such as windy sites.

Table II-4
EIA Forecasts of Estimated Costs of Electricity Generation Alternatives
¢/kWh (2007 dollars)

Plant Type	2020	2030
Conventional Coal	92.6	81.9
Advanced Coal	99.8	84.4
Advanced Coal with CCS	113.5	93.1
Natural Gas-fired		
Conventional Combined Cycle	85.8	87.3
Advanced Combined Cycle	81.4	81.8
Advanced CC with CCS	113.5	106.2
Conventional Combustion Turbine	143.4	145.7
Advanced Combustion Turbine	125.6	120.3
Advanced Nuclear	101.8	84.1
Wind	138.8	118.7
Wind – Offshore	219.8	176.6
Solar PV	369.5	268.4
Solar Thermal	247.3	187.1
Geothermal	96.8	83.9
Biomass	103.0	85.8
Hydro	111.5	95.9

Source: U.S. Energy Information Administration, 2009.

In the AEO 2009 reference case, a three percentage point increase in the cost of capital is added when evaluating investments in GHG intensive technologies like coal-fired power plants without CCS and CTL plants. While the this adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of a $15 per ton CO_2 emissions fee when investing in a new coal plant without CCS, well within the range of the results of simulations that utilities and regulators have prepared. According to EIA, the adjustment should not be viewed as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions. As a result, the levelized capital costs of coal-fired plants without CCS are higher than would otherwise be expected.[43]

II.D. LCOE Cost Estimate Concerns

There are serious, complex issues concerning LCOE estimates for electric power generation alternatives, especially for nuclear power and for renewables.

Nuclear LCOE Issues

The construction costs of nuclear plants completed during the 1980s and early 1990s in the U.S. and in most of Europe were very high — and much higher than currently predicted by the utilities now building nuclear plants and by the nuclear industry in general. The reasons for the poor historical construction cost experience are not well understood and have not been studied carefully. The realized historical construction costs reflected a combination of regulatory delays, redesign requirements, construction management problems, and quality control problems. Further, construction on few new nuclear power plants has been started and completed anywhere in the world in the last decade. The information available about the true costs of building nuclear plants in recent years is also limited.[44]

The track record for the construction costs of nuclear plants completed in the U.S. during the 1980s and early 1990s was poor, and actual costs were far higher than had been forecast. Construction schedules experienced long delays, which, together with increases in interest rates, resulted in high financing charges. New regulatory requirements also contributed to the cost increases, and in some instances, the public controversy over nuclear power contributed to some of the construction delays and cost overruns. However, while plants in Korea and Japan continue to be built on schedule, some of the recent construction cost and schedule experience, such as with the plant under construction in Finland, has not been encouraging.[45] Whether the lessons learned from the past have been factored into the construction of future plants has yet to be seen, and these factors have a significant impact on potential costs and the risk facing investors financing a new build.

As noted in the MIT 2009 update, since 2003 construction costs for all types of large-scale engineered projects have escalated dramatically. The estimated cost of constructing a nuclear power plant has increased at a rate of 15 percent per year

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[43]EIA, "Levelized Cost of New Generation Resources from the Annual Energy Outlook 2009," op. cit.
[44]See the discussion in Massachusetts Institute of Technology, *The Future of Nuclear Power*, op. cit.; Massachusetts Institute of Technology, *Update of the MIT 2003 Future of Nuclear Power Study*, op. cit.; and Roger H. Bezdek, "Nuclear Power Economics and Prospects in the USA," op. cit.
[45]The original estimated cost of the Finnish Olkiluoto nuclear power plant was about $4.3 billion, but has now increased by about $3.3 billion – nearly 80 percent. The reactor was originally scheduled to have gone online the summer of 2009, but Areva, the French nuclear construction company building the plant, is no longer is committing to any dates for its completion. Henna Aaltonen, *International Herald Tribune*, September 2, 2009.

heading into the current economic downturn. This is based both on the cost of actual builds in Japan and Korea and on the projected cost of new plants planned for in the U.S. Capital costs for both coal and natural gas have increased as well, although not by as much. The cost of natural gas and coal that peaked sharply is now receding and, taken together, these escalating costs leave the situation about where it was in 2003.[46]

Accordingly, the future construction costs of building a large fleet of nuclear power plants is necessarily uncertain, although the potential for high construction costs has been a major factor leading to very little credible commercial interest in investments in new nuclear plants. Finally, while average U.S. nuclear plant availability has increased steadily during the 1990s to a high of 90 percent in 2001, many nuclear plants struggled with low availabilities for many years and the life-cycle availability of the fleet of nuclear plants (especially taking account of plants that were closed early) is much less than 90 percent. In addition, the average operation and maintenance costs of U.S. nuclear plants is about $18/MWe-hr, rather than the $10/MWe-hr often assumed in many paper engineering cost studies.[47]

For this reason, the 2003 MIT report applied a higher weighted cost of capital to the construction of a new nuclear plant (10 percent) than to the construction of a new coal or new natural gas plant (7.8 percent). The 2003 report found that capital cost reductions and construction time reductions were plausible, but not yet proven – this judgment remained unchanged in the 2009 MIT update study. Thus: "The challenge facing the U.S. nuclear industry lies in turning plausible reductions in capital costs and construction schedules into reality,"[48] and the following questions remain to be answered:

- Will designs truly be standardized, or will site-specific changes defeat the effort to drive down the cost of producing multiple plants?
- Will the licensing process function without costly delays, or will the time to first power be extended, adding significant financing costs?
- Will construction proceed on schedule and without large cost overruns?

The first few U.S. plants will be a critical test for all parties involved, and the risk premium will be eliminated only by demonstrated performance. Current estimates are not encouraging: The cost of a new generation III nuclear power plant is estimated to be as much as $6,700 per kW, compared to $2,300 per kW for a new coal plant and $850 per kW for a natural gas plant.[49]

[46]See the discussion in Massachusetts Institute of Technology, *Update of the MIT 2003 Future of Nuclear Power Study*, op. cit.; and Roger H. Bezdek, "Nuclear Power Economics and Prospects in the USA," op. cit.
[47]Ibid.
[48]Massachusetts Institute of Technology, *Update of the MIT 2003 Future of Nuclear Power Study*, op. cit.
[49]Rebecca Smith, "The New Nukes," *Wall Street Journal*, September 8, 2009, pp. R1 – R3.

In the latest EIA forecasts, two nuclear power plant cost cases analyze the sensitivity of the projections to lower and higher costs for new plants.[50] The cost assumptions for the low nuclear cost case reflect a 25 percent reduction in the capital and operating cost for the advanced nuclear technology in 2030, relative to the reference case. Since the reference case assumes some learning occurs regardless of new orders and construction, the reference case already projects a 29 percent reduction in capital costs between 2009 and 2030. The low nuclear cost case assumes a 46 percent reduction between 2009 and 2030. The high nuclear cost case assumes that capital costs for the advanced nuclear technology do not decline from 2009 levels. The high nuclear cost case also assumes that all existing nuclear plants will retire after 55 years, rather than allowing operation to 60 years. This results in a total of 31 GW of retirements by 2030.

EIA notes that the costs to build new power plants have risen dramatically in the past few years, driven primarily by significant increases in the costs of construction related materials, such as cement, iron, steel and copper. For the *AEO 2009* reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates in the early part of 2008. A cost adjustment factor based on the projected producer price index for metals and metal products was also implemented, allowing the overnight costs to change over time following the index. Although there is significant correlation between commodity prices and power plant costs, there may be other factors that influence future costs that raise the uncertainties surrounding the future costs of building new power plants.

Finally, even if an investment in nuclear power appears attractive on a spreadsheet, analysts must confront the regulatory and political challenges associated with obtaining a license to build and operate a plant on a specific site. In the past, disputes about licensing, local opposition, cooling water source and discharge requirements, etc., have delayed construction and completion of nuclear plants. Many planned plants, some of which had incurred considerable development costs, were cancelled.

Renewables

Deriving accurate, consistent, and comparable LCOE estimates for renewable technologies such as wind, solar thermal, and PV is extremely difficult and subject to much uncertainty, and it may not even be possible to meaningfully compare the levelized costs of dispatchable and non-dispatchable energy sources. Renewables suffer of the interrelated problems of low and highly variable capacity factors, intermittency, unreliability, need for storage and backup, requirements for expanded transmission, and heavy reliance on government subsidies and government-mandated utility subsidies.

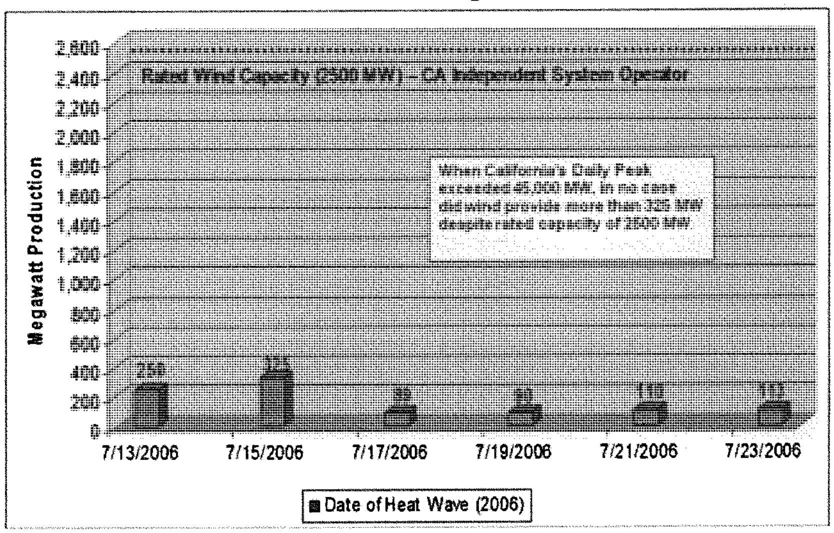
For example, while fossil and nuclear plants can have capacity factors close to 90 percent, the estimated capacity factor that EIA uses for wind is 34 percent, for solar

[50]EIA, "Electricity Market Module," Report #:DOE/EIA-0554 (2009), March 2009.

thermal is 31 percent, and for PV is 22 percent. While these appear to be generally reasonable as a national averages, they also may be somewhat high – e.g., other estimates of wind capacity factors are in the range of 25 – 30 percent.[51] Thus, an accurate LCOE for these renewables must, at a minimum, take into account these low capacity factors. However, even such an adjustment may not fully account for the fact that few renewable resources may actually be available when they are needed the most.

As shown in Figure II-8, during the California heat wave in July 2006, which resulted in significant increases in electricity demand, actual wind generation was at only about five percent of available capacity. Thus, in this case, the capacity factor for wind was closer to five percent than 34 percent.

Figure II-8
Wind Generation's Performance During 2006 California Heat Wave



Source: U.S. Department of Energy, 2006.

[51]They could be even lower. For example, Boccard notes that "For two decades, the capacity factor of wind power measuring the mean energy delivered by wind turbines has been assumed at 35% of the name plate capacity. Yet, the mean realized value for Europe over the last five years is closer to 21% thus making levelized cost 66% higher than previously thought." Nicolas Boccard, "Capacity Factor of Wind Power: Realized Values vs. Estimates, October 2008, available at: http://ssrn.com.

Similar problems have been encountered in Texas, which also has an aggressive wind power program. In 2008, the state installed nearly 2,700 MW of new wind capacity, and if Texas were an independent country, it would rank sixth in the world in terms of total wind power production capacity. However, the Electric Reliability Council of Texas (ERCOT) has analyzed the capacity factor of wind and estimated it to be less than nine percent. In a 2007 report, ERCOT determined that only "8.7 percent of the installed wind capability can be counted on as dependable capacity during the peak demand period for the next year." It went on to say "Conventional generation must be available to provide the remaining capacity needed to meet forecast load and reserve requirements." In 2009, ERCOT re-affirmed its decision to use the 8.7 percent capacity factor.[52]

Texas currently has about 8,200 MW of installed wind power capacity. However, ERCOT, in its forecasts for 2009 summer's demand periods when electricity use is the highest, estimated that only 708 MW (8.6 percent) of the state's wind power capacity could actually be counted on as reliable. With total summer generation needs of 72,648 megawatts, that implies that wind power was providing only one percent of Texas's total reliable generation portfolio. And ERCOT's projections show that wind will remain a nearly insignificant player in terms of reliable capacity through at least 2014, when it expects wind to provide about 1.2 percent of its needed generation. Thus, Texas will continue to rely almost entirely on natural gas, coal, and nuclear power to generate electricity.

The experience of the Pacific Northwest – another region with an aggressive wind program – is similar. The region's experience is that when electric power is needed most, the wind is not blowing: Often when it very hot or very cold and electric power demand is greatest, wind generation is simply not available. For example, during the cold days of January 5 to 28, 2009 wind generation in the region was virtually non-existent.[53]

As noted, EIA contends that its RE LCOE forecasts for RE (shown in Table II-4) include a capacity factor for wind of 34 percent, for solar thermal of 31 percent, and for PV of 22 percent. However, if actual capacity factors are much lower than this, the LCOE estimates for these RE technologies may have to be increased significantly.

At least as important, it is not clear how the required costs of backup power should be accurately incorporated into the RE LCOE estimates. Given the inherent unreliability and intermittency of RE technologies, near 100 percent backup may be required – as has been the case in Germany. Further, given that RE resources may not be reliably available when they are needed the most, 24x7 spinning reserve may be often required. Because of this need for full fossil fuel backup, there is a large premium for solar and wind -- paying once for the solar and wind system and again for the fossil fuel system, which must be kept running at a low level at all times to be able to quickly ramp up in cases of sudden declines in sunshine and wind. Thus, the total cost of such

[52]Robert Bryce, "Texas Wind Power: The Numbers Versus the Hype," *Energy Tribune*, August 05, 2009.
[53]http://www.transmission.bpa.gov/business/operations/wind/WindGen_VeryLow_Jan08Jan09x.xls

a system should include the cost of the solar and wind machines and the cost of the full backup power system running in spinning reserve.[54]

Backup charges for RE systems can be substantial and they are already being imposed – this is not an issue for the distant future. For example, in 2009 Bonneville Power Administration ruled that wind generators will face a new charge over the next two years. Pending likely approval by FERC this fall, a new wind integration charge will be levied on all wind generators at a rate of 5.7¢/ kWh.[55] In the past, BPA charged some of its utility customers for conventional power reserves to back up intermittent wind power; however, the amount of wind on BPA's system has grown rapidly in recent years, increasing both the need for reserves and the risks to system reliability. BPA has found that increased size of the wind fleet was compounded by the wind generators' inability to accurately account for wind ramp events in their schedules, thereby requiring BPA to hold a significantly larger amount of reserves in order to provide balancing services.

This is a very significant charge:

- EIA estimates that the average annual electricity price in 2010 will be 8.3¢/kWh, and a rate surcharge of 5.7¢/kWh thus represents an increase of 69 percent
- Current electricity rates in the Pacific Northwest range between 5¢/kWh and 6¢/kWh, and a rate surcharge of 5.7 ¢/kWh is about 100 percent.

Thus, the costs need to include the costs of the wind generator plus the imputed costs of backup power. Including backup would provide a dispatchable system, whose costs could be legitimately compared with coal and other baseload options. While comprehensive analysis of the required backup issue is outside the scope of the current project, it is clear that if such costs are incorporated into the LCOE of RE, these cost estimates would increase significantly.

In addition, there is the question of how the costs of the increase transmission requirements of RE systems should be included in the LCOE of these systems. This issue is often framed as the difficulty of getting power from RE sites, such as the southwest for solar thermal and the great plains for wind, to the major demand centers in cities on the coasts. Costly transmission lines will be needed to move solar and wind energy to the major U.S. population centers, and there must be considerable redundancy in those new transmission lines to guard against damage due to natural disasters and terrorism. All of this leads to considerable additional costs.[56] Legislation has even been introduced in the U.S. Congress for "green transmission" lines that

[54]James Schlesinger and Robert Hirsch, "Getting Real on Wind and Solar," *Washington Post*, April 24, 2009.
[55]Charles Redell, "NW Utilities Get Wind of Integration Charge," *Reuters*, August 12, 2009,
[56]Schlesinger and Hirsch, op. cit.

would be restricted exclusively to electricity form RE sources.[57] While the feasibility of such proposals is questionable, if such lines are actually built it would seem that all of their costs should be incorporated into the LCOE for RE.

However, the RE transmission cost issue is more local and immediate, and individual states and regions are already having to deal with it. Recent estimates indicate that these costs add 30 to 40 percent more to the cost of wind resources.[58] The issue of who should pay for transmission lines needed to carry wind energy from Midwestern states has also arisen over a proposal filed with FERC in July 2009.[59] The proposal filed by Midwest Independent System Operators would shift as much as 90 percent of the cost of transmission upgrades onto generators such as wind farms. The filing was in response to a Minnesota utility that complained that its customers would bear half the cost of shipping wind electricity generated in North Dakota and South Dakota to cities outside of its area. Midwest Independent System Operators, which oversees the grid in Iowa and 12 other Midwestern states, currently uses a 50-50 cost division for transmission upgrades.

The filing with FERC raises a question that must be faced on a larger scale when Iowa and other states become homes to a new transmission line that will ship electricity generated by wind farms in Iowa into cities in Illinois and farther east. The sums involved – and the potential kWh charges, are nontrivial: ITC Holdings has preliminary commission approval for a $12 billion, 765-KV transmission line to carry wind energy from Iowa and other Midwestern states from the Upper Midwest into Illinois.[60]

EIA contends that their LCOE estimates take the differing capacity factors into account and that no adjustment is necessary. However, the EIA cost estimates represent only the costs of building and operating the various technologies. EIA recognizes issues such as availability, backup, etc. that can definitely influence the capacity decisions and are a major reason why the levelized costs are not really a good "explanatory" basis for the capacity decisions. For example, wind may be built simply as a "fuel saver" so no backup capacity would be required,[61] or it might be built to contribute to the need for more capacity, in which case some backup capacity could be necessary. Also, some technologies have subsidies such as Investment Tax Credits or Production Tax Credits that can influence the capacity decisions.[62]

EIA thus cautions that there are availability and system reliability issues (particularly for intermittent sources) so that renewables cannot really be directly compared to other technologies simply on the basis of these costs. "The model used for our projections does represent these considerations when making the capacity

[57]For example, see the "Clean Renewable Energy and Economic Development Act," a bill introduced by Senator Harry Reid in the 111th Congress.
[58]Northwest Power and Conservation Council, "Review of Generating Resource Options for the Sixth Power Plan," January 2009.
[59]Dan Piller, "Plan Sparks Row Over Wind Transmission," *Des Moines Register*, August 15 2009.
[60]Ibid.
[61]If wind is viewed solely has a fuel saver, it would be a very expensive one
[62]EIA staff communications with MISI, August and September 2009.

decisions, but it is not really possible to incorporate these factors in the levelized cost estimates."[63]

Another issue of concern is that construction costs for new power plants have increased at an extraordinary rate over the past several years.[64] One study, published in mid-2008, reported that construction costs had more than doubled since 2000, with most of the increase occurring since 2005.[65] Construction costs have increased for plants of all types, including coal, nuclear, natural gas, and wind.

The cost increases can be attributed to several factors, including high worldwide demand for generating equipment, rising labor costs, and, most importantly, sharp increases in the costs of materials (commodities) used for construction, such as cement, iron, steel, and copper. Commodity prices continued to increase through most of 2008, but as oil prices dropped precipitously in the last quarter of the year, commodity prices began to decline. The most recent power plant capital cost index published by Cambridge Energy Research Associates (CERA) shows a slight decline in the index over the past 6 months, and CERA analysts expect further declines.[66]

The current financial situation in the U.S. will also affect the costs of future power plant construction. Financing large projects will be more difficult, and as the slowing economy leads to lower demand for electricity, the need for new capacity may be limited. The resultant easing of demand for construction materials and equipment could lead to lower costs for materials and equipment when new investment does take place in the future. Fluctuating commodity prices, combined with the uncertain financial environment, increase the challenge of projecting future capital costs.

Because some plant types – especially nuclear and most renewables -- are much more capital-intensive than others, the mix of future capacity builds and fuels used can differ, depending on the future path of construction costs. If construction costs increase proportionately for all plant types, natural-gas-fired capacity will become more economical than more capital-intensive technologies.[67]

Finally, while EIA contends that tax incentives are not included in the RE LCOE estimates, it acknowledges that tax subsidies and incentives have been an important factor in the growth of renewable generation over the past decade, and that they could continue to be important in the future. The Energy Tax Act of 1978 established ITCs for wind, and EPACT 92 established the Renewable Electricity Production Credit (more

[63]Ibid.

[64]AEO 2009.

[65]Cambridge Energy Research Associates, "Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index," May 27, 2008,

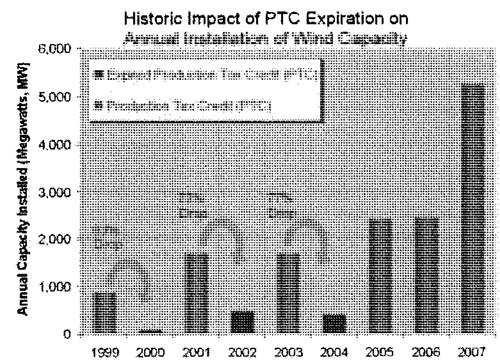
[66]Cambridge Energy Research Associates, "IHS CERA Power Capital Costs Index Shows Power Plant Construction Costs Decreasing Slightly," December 17, 2008,

[67]Another issue concerns EIA's forecasts of significant cost decreases in the costs of new renewables builds over the next two decades, at least partially on the basis of learning. However, the National Research Council, in meetings on the hybrid vehicle program, has noted that some of these technologies may be "learned out." That is, there may be little cost reductions possible from further learning.

commonly called the PTC) as an incentive to promote certain kinds of renewable generation beyond wind on the basis of production levels. Specifically, the PTC provided an inflation-adjusted tax credit of 1.5¢/kWh for generation sold from qualifying facilities during the first 10 years of operation.

The federal renewable energy production tax credit (REPTC) currently provides a 2.1¢/kWh incentive (indexed to inflation) for the production of electricity from utility-scale wind turbines. It is the most important federal RE electricity incentive and has been absolutely critical in subsidizing and promoting wind generation in the U.S. – see Figure II-9.

Figure II-9



Source: American Wind Energy Association, 2008.

Since EIA forecasts that the average U.S. electricity price in 2010 will be 8.3 ¢/kWh, REPTC alone represents an (indexed) electricity production subsidy of more than 25 percent.

The 1992 PTC has lapsed periodically, but it has been renewed before or shortly after each expiration date, typically for an additional 1- or 2-year period. In addition, eligibility has been extended to generation from many different renewable resources, including poultry litter, geothermal energy, certain hydroelectric facilities, "open-loop" biomass, landfill gas, and marine energy resources.

The PTC has contributed significantly to the expansion of the wind industry over the past 10 years, and since 1998, wind capacity has grown by an average of more than 25 percent per year. Although other renewable generation facilities, such as geothermal or poultry litter plants, have been able to claim the PTC, none has grown as dramatically as wind power.

Because *AEO 2009* represents only those laws and policies in effect on or before November 4, 2008, the renewable energy PTC is assumed to expire at the end of 2009 for wind and at the end of 2010 for other eligible renewables. However, the program has a long history of renewal and extension, and there is considerable interest, both in Congress and in the renewable energy industry, in keeping the credit available over the longer term, as seen in the recent extension to 2013.

To examine the potential impacts of a PTC extension, *AEO 2009* included a production tax credit extension case that examines the potential impacts of extending the current credit through 2019. This results in significant additional growth in wind capacity, with total capacity increasing to approximately 50 GW in 2020, as compared with 33 GW in the reference case.

Further, some states have RE incentives that dwarf the federal incentives. For example, the state of Washington has an RE feed-in tariff of 15¢/kWh – and 54¢/kWh if the RE equipment is manufactured in the state.[68] By comparison, the current average electric rate in Washington is about 6.1¢/kWh

In sum, realistic increases in RE LCOE estimates may be required due to factors such as:

- Intermittency and reliability
- Backup requirements
- Transmission charges
- Capital cost increases
- Government subsidies and mandates

These are discussed further in Chapter V

Finally, it also has to be recognized that any new fossil power plant builds in the future will be much more expensive if they include the full costs of CCS. For example, a recent study[69] estimated that:

- For First-of-a-Kind plant using solid fuels the levelized cost of electricity on a 2008 basis is approximately 10¢/kWh higher with CCS than for conventional plants (with a range of 8-12 ¢/kWh).
- For mature technologies (Nth-of-a-Kind plant) the additional cost of electricity with capture is approximately 2-5¢/kWh
- Since the EIA forecast of the 2010 electricity price is 8.3¢/kWh, the LCOEs of new fossil plants could be between 50 percent and 100+ percent more expensive than those of the current fleet.

[68]"Solar Hero," *Solar Today*, September/October 2009, p.14.
[69]Mohammed Al-Juaied and Adam Whitmore, "Realistic Costs of Carbon Capture," Discussion Paper 2009-08, Kennedy School of Government, Harvard University, July 2009.

III. METHODOLOGICAL ISSUES AND ELASTICITY ESTIMATES

Few studies have attempted to estimate the long run impacts of changes in energy and electricity prices on the economy and jobs. Here we:

- Review two recent studies that provide guidance on methodology and data
- Summarize a number of studies that quantified the elasticity of economic variables with respect to changes in energy and electricity prices

III.A. Estimating the Impact of Energy Prices on the Economy and Jobs

Penn State Study

This study forecast the likely impacts of coal utilization for electricity generation on the economies of the 48 contiguous states in 2015.[70] The authors first estimated the overall economic benefits associated with the availability of coal as a relatively low-cost fuel resource. This "existence" value reflects the increased economic output, earnings, and employment associated with projected coal utilization for electricity generation in 2015. They also estimated the net economic impacts of displacing 33 percent and 66 percent of projected coal generation by alternative energy resources, taking into account the positive economic effects associated with alternative investments in oil, natural gas, nuclear, and renewable energy supplies. Our interest here is in the methodology and data used in the Penn State to estimate the price advantage represented by coal as a low cost electricity generation technology.

Measuring Economic Interdependence

The authors noted that, with a broad base and high level of technological advancement, the U.S. economy exhibits a great deal of interdependence. Each business enterprise relies on many others for inputs into its production process and provides inputs to them in return. This means that the coal and coal-based electric utility industries' contributions to the nation's economy extend beyond their own production to include demand arising from a succession of "upstream" inputs from their suppliers and "downstream" deliveries to their customers. The economic value of these many rounds of derived demands and commodity allocations is some multiple of the value of direct production itself.

Thus, the coal and coal-based electric utility industries generate "multiplier" effects throughout the U.S. economy. The first round of demand impacts is obvious -- the direct inputs to electricity generation, including coal and primary factors (labor and

[70] Rose, Adam, and Dan Wei, *The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015,* report prepared for the Center for Energy and Economic Development, Inc., Alexandria, Virginia, the Pennsylvania State University, July 2006.

capital). Subsequent rounds, or indirect demands for goods and services used by the providers of these inputs, however, thread their way through the economy in subtle ways, eventually stimulating every other sector in some way.

Similarly, they generate income that is transformed into consumer spending on still more products. All of this economic activity also generates local, state, and federal tax revenues, which, when spent by all three levels of government, creates still more multiplier effects.

Measuring Locational Attractiveness

A method of capturing the locational attractiveness of a good or service is not to claim the entirety of output of its direct and indirect users, but only an amount relating to the price advantage of the input over its competitors. In this study, the authors calculated a "price differential" between coal and alternative fuels in electricity production, and then estimated how much economic activity is attributable to this cost saving. For this purpose, they used an economy-wide elasticity of output with respect to energy prices that measures the percentage change in economic activity with respect to a 1.0 percent change in price. They analyzed a variety of sources of information to arrive at a value of 0.10, meaning that the availability of coal-fueled electricity at a price 10 percent lower than that of its nearest competitor is responsible for increasing total state or regional economic activity by 1.0 percent

Economic Impacts of Coal on State and Regional Economies, 2015

To assess the importance of coal to state and regional economies in 2015, the authors first estimated the level of coal-based electricity generation in each state in 2015 based on projections by EIA and EPA.[71] They evaluated coal-related impacts according to various assumptions embodied in their scenarios.[72]

Their set of scenarios estimated the positive impact on national and regional economic output, household income, and jobs attributable to the projected levels of coal-fueled electricity in 2015. These scenarios estimated the "existence" value of coal as the key fuel input into electricity generation in the U.S. The economic impacts of coal estimated in the study included two components: 1) the backward linkage, or demand-side multiplier, effects for coal-fueled electricity generation, and 2) the effects of the favorable price differential attributable to the relatively cheaper cost of coal-based electricity.

[71]They also assumed that the technological structure of the economy, embodied in individual state input-output tables, would remain unchanged over the projection period to 2015.
[72]These are detailed in Appendix B of the report.

The authors first used IMPLAN input-output tables to estimate the direct and indirect (multiplier) economic output, household income, and jobs created by coal-fueled electricity generation in each state.[73] They then evaluated the impacts of the favorable price differential attributable to coal-based electricity. Essentially, they measured the economic activity attributable to relatively cheaper coal in contrast to what would take place if a state were dependent on more expensive alternatives, which they assumed would be a combination of oil, natural gas, renewable, and nuclear electricity. They conducted two calculations: 1) an upper-range ("high") price scenario, and 2) a lower-range ("low") price scenario. These two scenarios had the same backward linkages effects, but different price differential effects based on their different energy price assumptions. As noted, they estimated the impact of higher electricity prices on state economies using a price elasticity estimate of 0.10.

Finally, they assigned equal weight to each of the two price scenarios to obtain the average "existence" impacts of coal-fueled electricity generation in 2015. They then derived results for each state and region in 2015 that showed that coal, as the low-cost electricity generation option, has significant economic and job benefits and that displacing coal in the generation mix would have severe economic consequences. For example, the study estimated the average impacts of displacing 33 percent of coal-based generation in 2015 at:

- $166 billion (2005$) reduction in gross economic output
- $64 billion reduction of annual household incomes
- 1.2 million job losses

National Coal Council Study

This study for the NCC estimated the economic impacts from coal Btu energy conversion, which affect all segments of the energy industry, including natural gas, crude oil, petroleum, and electricity.[74] The study noted that estimating the economic impacts from coal Btu energy conversion may at first seem a daunting task. The breadth of the conversion scenarios addressed affect all segments of the energy industry, and representation of how equilibrium energy prices and quantities adjust in each of these markets and their interactions in response to coal-based energy manufacturing was impossible given the resources and timeframe for this project. As a result, an aggregate energy supply and demand framework was utilized. This approach greatly simplified the analysis, distilling the effects down to a few key parameters, such as:

- The price elasticity of aggregate energy demand

[73]They estimated only the minimum backward linkage effects for the "multiplier" effects. Their method excluded all forward linkages (all the production that uses coal-fueled electricity directly or indirectly) and focuses only on the factor inputs of coal-based electricity generation, such as fuel and electric generating equipment.
[74]Tim Considine, *Coal: America's Energy Future*, Volume II, "Appendix: Economic Benefits of Coal Conversion Investments," prepared for the National Coal Council, March 2006.

- The elasticity of gross domestic product to energy price changes
- The output multipliers associated with energy output and plant construction

This study did not estimate these parameters from primary data but, rather, used estimates derived from the economic literature. The scenarios discussed in the study were aggregated into one key variable: The quantity of Btus delivered to energy consumers. This involved making assumptions about the size of Btu conversion plants and the thermal efficiencies of the conversion processes. Another key assumption involved timing. The actual adoption of these technologies in the marketplace depends upon how energy prices and energy conversion plant costs evolve over time. The author avoided making assumptions about such specific factors and instead used a smooth extrapolation technique that attempts to model a process of steady and accelerating adoption of Btu energy conversion technologies over to the year 2025.

Impacts on Energy Markets

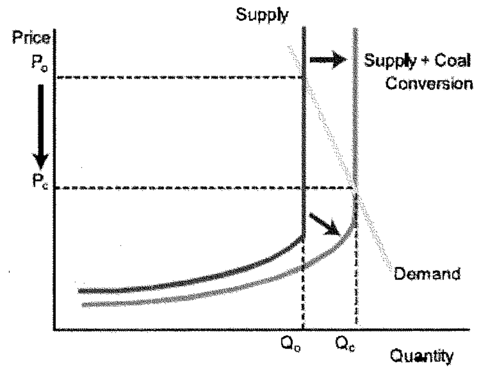
A key premise of the study is that the additional energy production from coal conversion will lower equilibrium energy prices, and the extent of the price reduction from additional energy production from coal depends upon the slope of the demand curve as illustrated in III-1.

Demand and supply relationships are characterized using elasticities. An own-price elasticity of demand is defined as the percentage change in quantity for a given percentage change in price, and its solution for the percentage change in price is as follows:

$$\varepsilon = \frac{\%\Delta Q}{\%\Delta P} \rightarrow \%\Delta P = \frac{\%\Delta Q}{\varepsilon}$$

The above equation provided a simple model for estimating the impacts of coal energy conversion on aggregate energy prices, and the author estimated the annual changes in quantities, which are the incremental supplies of energy products from coal conversion plants.

Figure III-1
Impacts of Coal Conversion on Energy Supply and Prices



Source: Economic Analysis Conducted at Penn State University, 2006

To compute the percentage change in quantity, the study used the long-term forecast of aggregate primary energy consumption produced by EIA. Own-price elasticities of energy demand vary considerably by product depending upon the degree of substitution possibilities and between the short-run -- when energy-consuming capital is for the most part fixed -- and the long-run, when investment allows much greater flexibility to respond to changing relative energy prices. For example, the short-run own price elasticity of demand for gasoline is about -0.2, while the long-run elasticity is at least -0.7. This study adopted an intermediate value of -0.3, based on the peer-reviewed literature, which can be interpreted as an intermediate-run elasticity.

The study found that the resulting energy price reductions (from the EIA reference case) from coal conversion would be significant, ranging from .04 percent in 2010 to more than 33 percent in 2025. This implies lower prices for electricity, natural gas, petroleum products, and many other energy products. This is significant given that coal conversion augments the nation's energy supply by more than 10 percent in 2025.

The study noted that a smaller own-price elasticity of demand in absolute terms or a steeper demand schedule in Figure III.1 would imply even sharper reductions in energy prices from coal energy conversion. Similarly, a larger absolute value for the own-price elasticity would imply a smaller impact on energy prices. The study's elasticity estimate of -0.3 can thus be viewed as a reasonable compromise between these two extremes.

Macroeconomics Impacts

The study noted that these energy price reductions act like a tax cut for the economy, reducing the outflows of funds from energy consumers to foreign energy producers. In addition, the supply-side push from additional domestic energy production will directly increase the nation's economic output. Finally, the plant construction will stimulate the economy at local, regional, and national levels. The study found these combined effects to be significant: Total real 2004 dollar GDP gains by the year 2025 exceed $600 billion, and the discounted present value of these gains, assuming a real discount of three percent, exceeds $3 trillion.

The study cautioned that these estimates should be considered only order of magnitude estimates given the wide range of uncertainty surrounding the coal energy conversion technology. In addition, such large-scale coal utilization could increase equilibrium prices for basic materials and services used to produce Btus from coal. To estimate these impacts, a general equilibrium model of energy markets and the economy would be needed.

The author noted that, even though electricity costs vary from state to state, coal generated electricity is among the lowest-cost power produced in the U.S. – see the discussion in Section II-B. The consumer cost-savings realized from using coal to generate electricity increase the disposable incomes of working families and, this income, when used to buy other goods and services, creates additional economic benefits.

III.B. Review of Elasticity Estimates in the Literature

A number of studies have developed estimates of the elasticity of GDP with respect to energy and electricity prices. Examples of these are summarized in Table III-1, and include the following:

- In 2009, Blumel, Espinoza, and Domper used Chilean data to estimate the long run impact of increased electricity and energy prices on the nation's economy.[75] They estimated that the elasticity ranged between -0.085 and -0.16.
- In 2008, in a study of the potential economic effects of peak oil, Kerschner and Hubacek reported elasticities in the range of -0.17 to -0.03 – although they noted that sectoral impacts are more significant.[76]

[75]Gonzalo Blumel, Ricardo A. Espinoza, and G. M. de la Luz Domper, "Does Energy Cost Affect Long Run Economic Growth? Time Series Evidence Using Chilean Data," Instituto Libertad y Desarrollo Facultad de Ingenier´ıa, Universidad de los Andes, March 22, 2009.
[76]Christian Kerschnera and Klaus Hubacek, "Assessing the Suitability of Input-Output Analysis For Enhancing Our Understanding of Potential Economic Effects of Peak-Oil," Sustainability Research Institute, School of Earth and Environment, University of Leeds, Leeds, UK, 2008.

- In 2008, Sparrow analyzed the impacts of coal utilization in Indiana, and estimated elasticities in the range of about -0.3 for the state.[77]
- In 2007, in a study of energy price GDP relationships, Maeda reported a range of elasticity estimates between -0.03 to -0.075.[78]
- In 2007, in a study of the relationship between energy prices and the U.S. economy, Citigroup found that in the long run, protracted high energy prices can have an economic impact and reported elasticities in the range of -0.3 to -0.37 between 1995 and 2005.[79]
- In 2007, in a study of oil-price GDP elasticities, Lescaroux reported a range of elasticities between -0.1 and -0.6.[80]
- In 2006, in an analysis of the likely impacts of coal utilization for electricity generation on the economies of the 48 contiguous states in the year 2015, Rose and Wei estimated the elasticity to be -0.1[81] They also reported that more recent studies for the state of Georgia and the UK yield similar results.
- In 2006, in a study of energy price impacts in the UK, Oxford Economic Forecasting found elasticities to range between about -0.03 and -0.07.[82]
- In 2006, in a study that analyzed the economic impacts from coal Btu energy conversion, Considine estimated an elasticity of -0.3.[83]
- In 2006, in a study of the impact of energy price increases in the UK, Global Insight estimated the elasticity to be -0.04.[84]
- In 2004, IEA employed energy-economic model simulation to calculate how much the increase in oil prices reduces GDPs in several countries. It found that the elasticity estimates ranged between -0.08 to -0.13.[85]
- In 2002, in a study of the economic impact of coal utilization in the continental U.S. Rose and Yang estimated the GDP electricity price elasticity of at -0.14.[86]

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[77]F.T. Sparrow, Measuring the contribution of coal to Indiana's economy, CCTR Briefing: Coal, Steel and the Industrial Economy, Hammond, IN, December 12, 2008.
[78]Akira Maeda, On the World Energy Price-GDP Relationship, presented at the 27th USAEE/IAEE North American Conference, Houston, Texas, September 16-19, 2007.
[79]PV Krishna Rao, "Surviving in a World with High Energy Prices, Citigroup Energy Inc., September 19, 2007.
[80]F. Lescaroux, An Interpretative Survey of Oil Price-GDP Elasticities, Oil & Gas Science and Technology Vol. 62 (2007), No. 5, pp. 663-671.
[81]Rose, Adam, and Dan Wei. *The Economic Impacts of Coal Utilization and Displacement in the Continental United States, 2015.* Report prepared for the Center for Energy and Economic Development, Inc., Alexandria, Virginia, the Pennsylvania State University, July 2006.
[82]Oxford Economic Forecasting, DTI Energy Price Scenarios in the Oxford Models, London, May 2006.
[83]Tim Considine, *Coal: America's Energy Future*, Volume II, "Appendix: Economic Benefits of Coal Conversion Investments." Prepared for the National Coal Council, March 2006.
[84]Global Insight, The Impact of Energy Price Shocks on the UK Economy: A Report to the Department of Trade and Industry, London, May 18, 2006.
[85]International Energy Agency, "Analysis of the Impact of High Oil Prices on the Global Economy," Paris, May 2004.
[86]Rose, A. and B. Yang. "The Economic Impact of Coal Utilization in the Continental United States,"

- In 2002, Klein and Kenny analyzed the results of six studies of the impacts of energy prices on the U.S. economy conducted between 1997 and 2002 and reported elasticity estimates that ranged between -0.6 and -1.3.[87]
- In 2001, Rose and Ramjan analyzed the impact of coal utilization in Wisconsin. They calculated a price differential between coal and natural gas in electricity production, and then estimated how much economic activity is attributable to this cost saving. They used an economy-wide elasticity of output with respect to energy prices, which they estimated to be -0.14.[88]
- In 2001, Rose and Ranjan surveyed recent studies of the impacts of energy prices on GDP and reported elasticities in the range of -0.5 to -0.25.[89]
- In 1999, Brown and Yucel surveyed a number of studies and reported an average elasticity of about -0.05.[90]
- In 1996, Rotemberg and Woodford analyzed the effects of energy price increases on economic activity and reported an elasticity of -0.25.[91]
- In 1996, Gardner and Joutz analyzed the relationship between economic growth, energy prices, and technological innovation, found that the real price of energy is negatively related to output in the US , and estimated that the elasticity is -0.72.[92]
- In 1996, in a study of the impact of energy prices on manufacturing, Hewson and Stamberg estimated an elasticity of -0.14.[93]
- In 1996, in studying postwar energy-GDP relationships, Hooker estimated that the elasticity ranges between -0.07 and -0.29.[94]
- In 1995, in a study of macroeconomic oil shocks, Lee and Ratti estimated the elasticity to be -0.1.4.[95]

Center for Energy and Economic Development; 2002.

[87]Daniel Klein and Ralph Kenny, "Mortality reductions from use of Low-cost coal-fueled power: An analytical framework," 21[st] strategies, Mclean, VA, and Duke University, December 2002.

[88] Adam Rose and Ram Ranjan, "The Economic Impact Of Coal Utilization In Wisconsin," Department of Energy, Environmental, and Mineral Economics, Pennsylvania State University, August 2001.

[89]Adam Rose and Ram Ranjan, "The Economic Impact Of Coal Utilization In Wisconsin," Department of Energy, Environmental, and Mineral Economics, Pennsylvania State University, August 2001.

[90]S.A. Brown and M.K. Yucel, "Oil Prices and U.S. Aggregate Economic Activity: A Question of Neutrality," *Economic and Financial Review*, second quarter, Federal Reserve Bank of Dallas, 1999.

[91] Rotemberg, Julio J., and Michael Woodford. 1996. "Imperfect Competition and the *." *Journal of Money, Credit, and Banking*, 28(4): 550–77.

[92] Fred Joutz and Thomas Gardner, "Economic Growth, Energy Prices, and Technological Innovation," *Southern Economic Journal*, vol. 62, 3, January, 1996, pp. 653-666.

[93] Hewson, T. and J. Stamberg. 1996. *At What Cost? Manufacturing Employment Impacts from Higher Electricity Prices,* Energy Ventures Analysis, Arlington, VA.

[94] See Mark A. Hooker, "What Happened to the Oil Price-Macroeconomy Relationship?," *Journal of Monetary Economics*, 38, 1996, pp. 195-213, and James D. Hamilton, "Oil and the Macroeconomy," Prepared for the *Palgrave Dictionary of Economics,* August 24, 2005.

- In 1982, in a study of industrial location and electricity prices, Anderson estimated the elasticity to be -0.14.[96]
- In 1981, Rasche and Tatom found that an energy price shock modifies the optimal usage of the existing stock of capital, modifying the optimal capital-labor ratio and generating an upward shift on the aggregate supply curve and a decline in potential output. They estimated that the elasticity of output with respect to the real price of energy ranges between -0.05 and -0.11.[97]

[95]Lee, Kiseok, and Shawn Ni Ronald A. Ratti (1995), "Oil Shocks and the Macroeconomy: The Role of Price Variability," Energy Journal, 16, pp. 39-56.
[96]Anderson, K. P., 1982. "Industrial Location and Electric Utility Price Competition," National Economic Research Associates, Inc., New York, NY.
[97]R.H. Rasche and J. A. Tatom, "Energy Price Shocks, Aggregate Supply, and Monetary Policy: The Theory and International Evidence," in K. Brunner and A. H. Meltzer, eds., *Supply Shocks, Incentives, and National Wealth*, Carnegie-Rochester Conference Series on Public Policy, vol. 14, Amsterdam: North-Holland, 1981.

Table III-1
Summary of Energy-GDP Elasticity Estimates

Year Analysis Published	Author	Elasticity Estimate
2009	Blumel, Espinoza, and Domper	-0.85 to -0.16
2008	Kerschner and Hubacek	-0.03 to -0.17
2008	Sparrow	-0.3
2007	Maeda	-0.03 to -0.75
2007	Citigroup	-0.3 to -0.37
2007	Lescaroux	-0.1 to -0.6
2006	Rose and Wei	-0.1
2006	Oxford Economic Forecasting	-0.03 to -0.07
2006	Considine	-0.3
2006	Global Insight	-0.04
2004	IEA	-0.08 to -0.13
2002	Rose and Young	-0.14
2002	Klein and Kenny	-0.06 to -0.13
2001	Rose and Ranjan	-0.14
2001	Rose and Ranjan	-0.05 to -0.25
1999	Brown and Yucel	-0.05
1996	Rotemberg and Woodford	-0.25
1996	Gardner and Joutz	-0.072
1996	Hewson and Stamberg	-0.14
1996	Hooker	-0.07 to -0.29
1995	Lee and Ratti	-0.14
1982	Anderson	-0.14
1981	Rasche and Tatom	-0.05 to -0.11

Source: Management Information Services, Inc., 2009.

In addition, numerous studies have examined the relationship between energy prices and GDP and found strong causality; for example:

- In 2008, Chontanawat found that the causality relationship is stronger in developed countries rather than developing countries.[98]
- In 2008, Bekhet and Yusop examined the long run relationship between oil prices, energy consumption, and macroeconomic performance in Malaysia over the period 1980-2005. Their findings indicated that there is a stable long-run relationship between oil prices, employment, economic growth, and the growth rate of energy consumption and also substantial short run interactions among them. The linkages and causal effects among prices, energy consumption and macroeconomic performance have important policy implications, and they found that the growth of energy consumption has significant impacts on employment growth.[99]
- In 2006, Soytas and Sari analyzed the causal relationship between energy consumption and GDP in G-7 countries and found that causality runs from energy consumption to GDP in these countries. They argued that energy conservation in some countries could negatively impact economic growth.[100]
- In 2006, Chontanawat, Hunt, and Pierse tested for causality between energy and GDP using a consistent data set and methodology for 30 OECD and 78 non-OECD countries.[101] They found that causality from aggregate energy consumption to GDP and GDP to energy consumption is found to be more prevalent in the developed OECD countries compared to the developing non-OECD countries. This implies that a policy to reduce energy consumption aimed at reducing GHG emissions is likely to have greater impact on the GDP of the developed rather than the developing world.

[98]Chontanawat, J. (2008) "Modeling causality between electricity consumption and economic growth in Asian developing countries", *Conference Paper*, presented at the 2nd IAEE Asian Conference, Perth, Australia, 5-7 November 2008.
[99]Hussain A. Bekhet and Nora Yusma Mohamed Yusop, "Assessing the Relationship Between Oil Prices, Energy Consumption and Macroeconomic Performance in Malaysia: Co-integration and Vector Error Correction Model (VECM) Approach," Finance and Economics Department, College of Business Management and Accounting.
University Tenaga Nasional, Pahang, Malaysia, 2008.
[100]U. Soytas and R. Sari, "Energy Consumption and GDP: Causality Relationship in G-7 Countries and Emerging Markets", *Energy Economics*, Vol. 25, 2006, pp. 33-37.
[101]Jaruwan Chontanawat, Lester C Hunt, and Richard Pierse, "Causality Between Energy Consumption and GDP: Evidence from 30 OECD and 78 Non-OECD Countries,"
Surrey Energy Economics Centre, Department of Economics, University of Surrey, UK, June 2006.

- In 1995, Finn found that in the U.S. the Solow residual tends to fall when energy price rises, implying a direct link between energy and production.[102]
- In 1987, Erol and You found a causal relationship running from energy consumption to output in a large set of industrialized countries.[103]

Other studies that came to similar conclusions include Al-Faris,[104] Al-Iriani,[105] Apergis, and Payne,[106] Davis and Haltiwanger,[107] Gronwald,[108] Harris,[109] Lee,[110] Manjulika and Koshal,[111] Narayan and Smyth,[112] Oligney,[113] Soytas and Sari,[114] Stern,[115] Stern and Cleveland,[116] and Wolde-Rufael.[117]

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[102]Mary G. Finn, "Variance properties of Solow's productivity residual and their cyclical implications," *Journal of Economic Dynamics and Control*, vol. 19, 1995, pp. 1249-1281, and Mary G. Finn, "Perfect Competition and the Effects of Energy Price Increases on Economic Activity," *Journal of Money, Credit, and Banking*, 32, 2000, pp. 400-416.
[103]Umit Erol and Eden H. S. Yu, "On the Causal Relationship between Energy and Income for Industrialized Countries", *Journal of Energy and Development*, Vol. 13, 1987, pp. 113-122; and Umit Erol and Eden H. S. Yu, H., 1987. "Time Series Analysis of the Causal Relationships Between U.S. Energy and Employment," *Resources and Energy*, vol. 9, 1987, pp. 75-89.
[104]A.R. Al-Faris, "The Demand for Electricity in the GCC Countries," *Energy Policy*, Vol. 30, 2002, pp. 117-124.
[105]Mahmoud A. Al-Iriani, "Energy-GDP relationship revisited: An example from GCC countries using panel causality," *Energy Policy*, vol. 34, November 2006, pp. 3342-3350.
[106]Nicholas Apergis and James E. Payne, Energy Consumption and Economic Growth: Evidence from the Commonwealth of Independent States, *Energy Economics*,
Vol. 31, September 2009, pp. 641-647.
[107]Steven J. Davis, and John Haltiwanger, "Sectoral Job Creation and Destruction Responses to Oil Price Changes," *Journal of Monetary Economics*, vol. 48, 1999, pp. 465–512, 2001.
[108]Marc Gronwald, "Large Oil Shocks and the US Economy: Infrequent Incidents with Large Effects," *The Energy Journal*; Vol. 29, 2008, pp. 151-171.
[109]Ethan S. Harris, Ethan S., et. al., "Oil and the Macroeconomy: Lessons for Monetary Policy", Working Paper for the National Science Foundation, February 2009.
[110]C.C. Lee, C. C., "The Causality Relationship between Energy Consumption and GDP in G-11 Countries Revisited", Energy Policy, Vol. 34, 2006, pp. 1086-1093.
[111]Manjulika Koshal, and Rajindar K. Koshal, "Production and High Energy Price: A Case of Japan and the United States", Decision Line, December/January 2001.
[112]Paresh Kumar Narayan and Russell Smyth, Russell, 2008. "Energy Consumption and Real GDP in G7 Countries: New Evidence From Panel Cointegration With Structural Breaks," *Energy Economics*, vol. 30, September 2008, pp. 2331-2341.
[113]Ron Oligney, "Energy and GDP are Closely Tied in US Economy, *Drilling Contractor*, November/ December 2003.
[114]R. Sari and U. Soytas, "Disaggregate Energy Consumption, Employment and Income in Turkey", *Energy Economics*, vol. 26, 2004, pp. 335-344.
[115]D.I. Stern, A Multivariate Cointegration Analysis Of The Role Of Energy In The U.S. Economy, Energy Economics, v. 22, 2000, pp. 267-283.
[116]Stern, David I. Stern and Cutler J. Cleveland, "Energy and Economic Growth" Rensselaer Working Papers in Economics, Number 0410, March 2004.
[117]Y.W. Rufael, Y. W. (2006), "Electricity Consumption and Economic Growth: A Time Series Experience of 17 African Countries", *Energy Policy*, Vol. 34, 2006, pp. 1106-1114; also see Paresh Kumar Narayan and Arti Prasad, Arti, 2008, "Electricity Consumption-Real GDP Causality Nexus: Evidence From A Bootstrapped Causality Test For 30 OECD Countries," *Energy Policy*, vol. 36, 2008, pp. 910-918.

Dahl has conducted extensive studies of NEMS elasticities and provided summaries of the elasticities within NEMS.[118] She noted that, since elasticities are a convenient way to summarize the responsiveness of demand to such things as own prices, cross prices, income, or other relevant variables, a substantial amount of resources have been devoted to estimating demand elasticities, at various levels of aggregation using a variety of models. Nevertheless, she found that considerable variation in the estimates at the aggregate and disaggregate levels remains.

[118]Carol Dahl, "A survey of energy demand elasticities in support of the development of the NEMS," Colorado School of Mines, October 1993; Carol Dahl and Carlos Roman, *Energy Elasticity Survey, presented at the* 24th Annual North American Colorado School of Mines Conference, Washington, D.C., July 8-10, 2004.

IV. DEVELOPMENT OF THE METHODOLOGICAL TOOL

As part of this analysis, a methodological tool was developed that permits the estimation of the economic and jobs impacts of changes in energy-related assumptions and variables. This tool was then utilized to conduct several illustrative scenarios and comparative analyses – these are discussed in Chapter V.

IV.A. Theoretical Framework

As described in the previous chapters, there are several major underpinnings to the methodology.

The first and most basic is that energy and energy prices – specifically electricity and electricity prices -- matter to the economy and theorizes that, in general, more abundant, efficient, and less expensive electricity is desirable and preferred and provides significant economic and jobs benefits. Electricity is a mainstay of the U.S. economy and a critical factor of production, so this assumption would appear to be straightforward and noncontroversial. However, as prior research has shown, this is not necessarily the case.[119]

Second, to quantify the relationship between electricity prices and the economy, the elasticity of GDP with respect to electricity prices is utilized. Extensive review of the literature indicates that a reasonable long run value for this elasticity is about -0.10. This indicates that a ten percent increase in electricity prices will result in a decrease in GDP of one percent. As discussed in Chapter III, a wide range of estimates for this value have been made over the past several decades in the U.S. and elsewhere, but a value of -0.10 is credible and defensible and has been used in rigorous studies of the impact of energy and electricity on the economy.[120]

In the spreadsheet the tool, this elasticity estimate can be varied by the user to simulate the different effects on the economy and jobs. Clearly, the higher the value used for the elasticity estimate the more impact that changes in electricity prices will have, and vice-versa. However, using values significantly higher than -0.10 runs the risk of overestimating the impact of electricity prices on the economy, while using values significantly lower than -0.10 runs the risk of underestimating the impact of electricity prices on the economy,

Third, the methodology posits that the mix of electric generating capacity – existing and new -- among the various fossil, nuclear, and renewable sources will significantly affect electricity prices. As discussed in Chapter II, the estimates of the LCOE costs of existing and, especially, new electricity generating technologies vary by

[119]NETL, *Literature Review of Employment Impact Studies of Power Generation Technologies,* DOE/NETL-2009/1381, September 14, 2009.

[120]See, for example, Blumel, Espinoza, and Domper, op. cit., Rose and Wei, op cit., Considine, op. cit., and International Energy Agency, "Analysis of the Impact of High Oil Prices on the Global Economy," op. cit.

orders of magnitude. Nevertheless, it seems clear that coal and hydro are the least expensive, followed by natural gas. New builds of nuclear and renewables are the most expensive and, among renewables, geothermal and biomass are the least expensive, followed by onshore wind, offshore wind, solar thermal, and PV.[121]

Fourth, the methodology assumes that there is a quantifiable relationship between economic activity and jobs – between the level of GDP and jobs. This is relatively noncontroversial, although the nature of the relationship is contentious. Here, for convenience, we assume that the relationship is linear, but changes over time as productivity increases. Specifically:[122]

- In 2010, $1 billion (2007 dollars) generates 10,040 jobs
- In 2020, $1 billion (2007 dollars) generates 8,520 jobs
- In 2030, $1 billion (2007 dollars) generates 6,965 jobs

In the tool simulations conducted, these values were fixed for each relevant year. However, the tool allows changes in the relationship as a user option. Increasing the number of jobs created per billion dollars of GDP implies slower productivity growth, while decreasing the number of jobs created per billion dollar of GDP implies more rapid productivity growth.

Finally, the scenarios developed here all assessed the impacts of replacing exiting coal-fired electricity generating capacity with various alternatives – primarily new nuclear and renewables, although simulations of limited replacement by coal with CCS and natural gas with CCS were also conducted. However, the tool is flexible enough to consider a wide range of fossil, nuclear, and renewable options.

The coal reduction scenarios were modeled here because a major objective of this project was to estimate the potential economic and jobs impacts of shifts away from coal as an electricity generation source. Further, most policy proposals currently being made advocate changes in this direction – for example, few are advocating that coal should replace future renewables builds. Thus, it is important to estimate the potential impacts on the economy of this replacement of coal capacity.

Nevertheless, as demonstrated in Chapter V, existing coal plants produce inexpensive electricity and replacing them with much higher cost nuclear and renewable facilities (or coal/CCS and NG/CCS facilities) will, inevitably, cause electricity prices to increase significantly.[123] All indications are that new builds will generate LCOEs that could be orders of magnitude higher than LCOEs from existing coal plants. The tool

[121]No new builds of large hydro are assumed here.
[122]These estimates were derived from the EIA AEO 2009 report.
[123]This is true for other perturbations as well. For example, advocates in the Pacific Northwest are recommending that some existing dams be torn down and that the electricity generation lost be replaced with renewables. Hydro power is less costly by orders of magnitude than renewable electricity, and the MISI tool could be used to analyze these proposals as well.

can be used to estimate the impact of such a transformation on electricity prices, GDP, and jobs.

V.B. Parameters

The major parameters of the tool include: [124]

- Dollar base: Constant 2007 dollars, derived using the GDP deflator
- Years: 2007 through 2030
- Electricity generation options: The basic options currently in the model are coal, nuclear, natural gas, hydro, onshore wind, offshore wind, geothermal, solar thermal, PV, petroleum, biomass, and other. However, the tool can (and in several scenarios did) incorporate other generation options, such as coal/CCS, NG/CCS, Coal SC, IGCC, NGCC, advanced coal and NG technologies, wind with various backup options, unconventional hydro, etc.
- Electricity demand: Fixed for each year on the basis of AEO 2009 ARRA
- Electricity production among the generation options: Fixed for each year in the reference case on the basis of AEO 2009 ARRA
- Prices of the electricity generation options: Fixed for each year in the reference case on the basis of MISI research, although these can be changed by the user
- Average price of electricity: Fixed in the reference case but dependent in the simulations on the distribution and prices of the electricity generation options
- Elasticity of GDP with respect to the electricity price: Fixed here at -0.10, although this can be changed by the user
- GDP: Fixed for each year in the reference case on the basis of AEO 2009 ARRA
- Total jobs: Fixed for each year in the reference case on the basis of AEO 2009
- Relationship between GDP and jobs: Fixed for each year in the reference case on the basis of AEO 2009

The 2010 basic reference parameters are shown in Table IV-1.

[124]However, exceptions may have to be made in implementation. For example, in assessing the EIA Lieberman Warner analysis data from AEO 2007 and 2008 had to be used because they were used in the EIA report.

Table V-1
2010 Reference Parameters

Electric Power Sector – 2010	Consumption Tbtu	Consumption Percent	Est.Price c/kWh
Coal	20.7	51%	6.9
Nuclear	8.5	21%	11.0
Natural Gas	6.1	15%	7.8
Onshore Wind	1.1	3%	17.4
Other	4.1	10%	8.1
Hydroelectric	*2.7*	*7%*	6.2
Geothermal	*0.2*	*0%*	10.0
Offshore Wind	*0.0*	*0%*	29.3
Solar Thermal	*0.0*	*0%*	32.9
PV	*0.0*	*0%*	49.3
Petroleum	*0.6*	*1%*	14.0
Biomass	*0.3*	*1%*	10.3
Other	*0.3*	*1%*	10.0
Total	40.5	100.0%	
Calculated average price of electricity (cents/kWh)			8.30
2010 reference price of electricity (cents/kWh)			8.30

This results in an increase of electricity prices of:	0.0%
With electricity accounting for total U.S.	
2010 energy consumption at	41%
and GDP (trillion 2007$) at:	$11.6
and the elasticity of output to energy price of:	0.1
.......the reduction in U.S. GDP (billion 2007$) is:	-$0.0
With the average U.S. jobs/billion$ GDP ratio at :	10,200
.....the reduction in U.S. jobs (thousand FTE) is:	-0

V.C. Discussion and Caveats

The tool is simple and straightforward, but the spreadsheet tool can get complex very quickly, and hundreds of simulations are possible. Further, many straightforward additions to the tool and spreadsheet can be made that increase by orders of magnitude the number of simulations that can be conducted.

Possible parameters, variables, and assumptions in the current version that can be changed include the following:

- Year: Past years and forecast years 2010 through 2030
- The base year dollar can be changed
- Coal price advantage: Can be reasonably varied from 0 to 100%+, depending on alternatives and CCS, cap & trade, etc.

- Coal price advantage over individual fuels: Can also be varied widely
- Future electricity prices: Can be changed within a broad range depending on assumptions about future economic growth, new electric power plant builds, GHG control legislation, etc.
- The future LCOEs of the two dozen electricity generation options can be varied widely – and, given the discussion in Section II-D, may need to be.
- A detailed time series of the two dozen LCOE estimates for each of the generation options can be created for 2007 – 2030 and then used to develop electricity cost estimates on the basis of alternate projections of the distribution of electricity generation growth. This could also be used to "reverse engineer" EIA electricity price forecasts, as discussed in Chapter VI.
- Other electricity generation options can be added to the spreadsheet.
- Future estimates of total electricity requirements can be changed
- The future shares of the different generation options within the overall electricity mix can be varied greatly
- The time periods of these changes can be varied.
- U.S. GDP base forecasts can be varied
- Total U.S. employment in each year can be varied.
- The GDP/jobs ratio can be varied, depending on assumptions about productivity growth
- The elasticity estimates can be varied: On the basis of the literature, estimates in the range of -0.5 to -0.15 appear feasible

These and other changes in the existing tool can be simulated. More basically, the tool itself can be expanded to be more realistic; for example:

- Large variations in the share of the various generation options in the total electricity mix and the resulting changes in electricity prices can be expected to result in changes in GDP, and such changes could be made endogenous rather than exogenous.
- Similarly, as electricity and energy prices change significantly, productivity will likely be affected.
- There is clearly an important relationship between the LCOEs of the different generation options and the likely rates of growth in the generation mix, and this relationship could be made endogenous.
- An input-output component could be added to the tool to generate detailed sector, industry, employment, and occupational and skill estimates.
- No CO_2 estimates are currently contained in the tool, and these could be included based on the CO_2 profiles of the different generation options.
- Numerous other improvements and extensions are possible.

However, as more and more of these improvements and extensions are made, the tool begins to be transformed into an econometric model with appropriate feedback loops and interactions. This would be a very ambitious project and is outside the scope of the current work. Even its desirability can be questioned, since straightforward spreadsheet analysis can offer advantages in terms of cost, transparency, ease of use, and rapid turnaround over very large, complex models.

Finally, electricity is becoming a larger share of U.S. energy consumption: In 2000, it was 37 percent and EIA forecasts that in 2030 it will increase to nearly 43 percent.[125] Thus, whatever economic and jobs impacts electricity prices currently have on the economy, these impacts will be gradually increasing in the coming decades.

The following chapter illustrates the use of tool and spreadsheet to conduct policy scenarios and indicate their broad implications. These results offer further perspective on the tool, and some implications are discussed in Chapter VI.

[125]AEO 2002 and AEO 2009 ARRA.

V. SCENARIOS AND CASE STUDIES

In this chapter, we summarize five analyses conducted using the methodology and tool develop in previous chapters to obtain insight into the level of feedback to GDP that may be captured by NEMS:

- 2010 Test Case Scenarios
- 2020 Decarbonization Scenarios
- Assessment of the EIA Analysis of the Lieberman-Warner Bill
- Assessment of the High Macro $30 carbon tax case (from Activity III)
- Assessment of the High Renewables-based Power case (from Activity III)

V.A. 2010 Test Case Scenarios

Hypothetical test case scenarios were conducted to obtain an indication of the likely impact of substantially reducing U.S. coal-fired electricity generation in the near future and replacing it with natural gas and renewables. Accordingly, it was hypothesized that in 2010 coal-fired electricity generation is reduced by 25 percent and that half of the reduction is replaced by an increase in natural gas generation and half by increased renewables.

The base parameters were derived from the EIA AEO April 2009 update (ARRA) and the other sources discussed in Chapters II – IV. Table V-1 shows the 2010 base case assumptions used.

Test Case Scenario I

In test case scenario I:

- Coal electricity generation was reduced by 25 percent and replaced half by natural gas and half by renewables
- All other basic case reference parameters were unchanged.

The test case scenario I parameters are shown in Table V-2 and Figure V-1.

Table V-1
2010 Base Case Reference Parameters

Electric Power Sector -- 2010	Consumption Tbtu	Consumption Percent	Est.Price c/kWh
Coal	20.7	51%	6.9
Nuclear	8.5	21%	11.0
Natural Gas	6.1	15%	7.8
Onshore Wind	1.1	3%	17.4
Other	4.1	10%	8.1
Hydroelectric	*2.7*	*7%*	6.2
Geothermal	*0.2*	*0%*	10.0
Offshore Wind	*0.0*	*0%*	29.3
Solar Thermal	*0.0*	*0%*	32.9
PV	*0.0*	*0%*	49.3
Petroleum	*0.6*	*1%*	14.0
Biomass	*0.3*	*1%*	10.3
Other	*0.3*	*1%*	10.0
Total	40.5	100.0%	
Calculated average price of electricity (cents/kWh)			8.30
2010 reference price of electricity (cents/kWh)			8.30

Source: U.S. Energy Information Administration and Management Information Services, Inc., 2009.

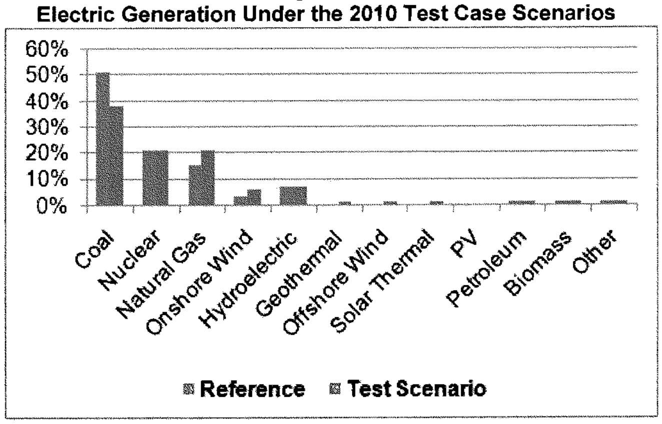
Table V-2
2010 Test Case Scenario I Parameters

Electric Power Sector -- 2010	Consumption Tbtu	Consumption Percent	Est. Price ¢/kWh
Coal	15.5	38%	6.9
Nuclear	8.5	21%	11.0
Natural Gas	8.7	21%	7.8
Onshore Wind	2.5	6%	17.4
Other	5.3	13%	12.4
Hydroelectric	*2.7*	*7%*	6.2
Geothermal	*0.3*	*1%*	10.0
Offshore Wind	*0.3*	*1%*	29.3
Solar Thermal	*0.3*	*1%*	32.9
PV	*0.2*	*0%*	49.3
Petroleum	*0.6*	*1%*	14.0
Biomass	*0.6*	*1%*	10.3
Other	*0.3*	*1%*	10.0
Total	40.5	100.0%	
Calculated average price of electricity (cents/kWh)			9.32
2010 reference price of electricity (cents/kWh)			8.30

The findings from this scenario, summarized in Table V-4, indicate that the 2010 economic and jobs impact is significant:

- Average electricity prices increase more than 12 percent
- GDP is $143 billion (2007 dollars) lower – 1.2 percent
- The job loss totals 1.4 million – slightly more than one percent.

Figure V-1
Electric Generation Under the 2010 Test Case Scenarios



Source: Management Information Services, Inc., 2009.

Test Case Scenario II

In this scenario, 2010 coal electricity generation was reduced by 25 percent and replaced half by natural gas and half by renewables. However, for reasons discussed in Section II-D, the estimated 2010 costs for nuclear power and for renewables may be optimistic. Therefore, in this scenario what may be more realistic nuclear and renewable costs were assumed:

- Actual 2008 nuclear costs of 13¢/kWh were used
- The 2010 LCOE costs for wind, PV and solar thermal in Scenario I were increased by 33 percent

Table V-3 shows the test case scenario II parameters.

As expected, the findings from this scenario, summarized in Table V-4, indicate that the 2010 economic and jobs impact is more significant than under scenario I:

- Average electricity prices increase nearly 25 percent
- GDP is $285 billion (2007 dollars) lower – 2.6 percent
- The job loss totals 2.9 million – slightly more than two percent.

Table V-3
2010 Test Case Scenario II Parameters

	Consumption		Est.Price
Electric Power Sector – 2010	Tbtu	Percent	c/kWh
Coal	15.5	38%	6.9
Nuclear	8.5	21%	13.0
Natural Gas	8.7	21%	7.8
Onshore Wind	2.5	6%	23.1
Other	5.3	13%	14.3
Hydroelectric	*2.7*	*7%*	6.2
Geothermal	*0.3*	*1%*	10.0
Offshore Wind	*0.3*	*1%*	40.0
Solar Thermal	*0.3*	*1%*	43.8
PV	*0.2*	*0%*	65.6
Petroleum	*0.6*	*1%*	14.0
Biomass	*0.6*	*1%*	10.3
Other	*0.3*	*1%*	10.0
Total	40.5	100.0%	
Calculated average price of electricity (cents/kWh)			10.34
2010 reference price of electricity (cents/kWh)			8.30

Source: Management Information Services, Inc., 2009.

Table V-4
Summary of 2010 Test Case Scenario Impacts

	Scenario I		Scenario II	
	Change	Percent	Change	Percent
Electricity prices (¢/kWh)	+1¢	+12.3%	+2¢	+24.5%
GDP (billion 2007$)	-$143	-1.2%	-$285	-2.6%
Jobs (thousands)	-1,400	-1.1%	-2,900	-2.1%

Source: Management Information Services, Inc., 2009.

V.B. 2020 Decarbonization Scenarios

The Proposal

In July 2008, former Vice President and Nobel Laureate Al Gore urged the U.S. to transform its entire electricity grid to carbon-free energy within 10 years, warning that drastic steps were needed to avoid a global economic and ecological cataclysm. Mr. Gore urged the spending of trillions of dollars to remake the U.S. power system: "The survival of the United States of America as we know it is at risk. And even more -- if more should be required -- the future of human civilization is at stake."[126]

He stated that the U.S. and the rest of the world were facing unprecedented problems, including growing demand for electricity, dangerous changes in the climate driven largely by emissions of carbon dioxide, and political instability in regions that produce much of the world's oil. "When we look at all three of these seemingly intractable challenges at the same time, we can see the common thread running through them, deeply ironic in its simplicity: Our dangerous over-reliance on carbon-based fuels is at the core of all three of these challenges -- the economic, environmental, and national security crises." His recommendation, which would require phasing out or substantially modifying virtually every existing U.S. coal-fired power plant by 2020, extends beyond what even the most ambitious scientists or analysts have proposed, as a means, he stated, of "jolting the world out of old ways of thinking. "Specifically, to those who say 10 years is not enough time, I respectfully ask them to consider seriously what the world's scientists are telling us about the risks we face if we don't act in less than 10 years."

It is a bold and extremely ambitious goal given the likely costs and the changes to the U.S. electricity system that would be required. Mr. Gore admitted that his plan would, at least initially, increase energy prices, but he proposed a payroll tax cut to offset higher prices for fuel and electricity. He noted that the U.S. uses only a tiny fraction of the wind, solar, and geothermal power available and that entrepreneurs were investing billions of dollars in new technology and rapidly reducing the costs of alternative energy sources.

Mr. Gore's proposal was less a step-by-step plan than a sweeping call to action. His path to a decarbonized electrical supply recommends more investment in solar and wind, keeping nuclear in the mix, maximizing energy efficiency, implementing CCS for at least some existing fossil fuel plants, and shifting to electric cars. His proposed solution is to eliminate all carbon-emitting forms of electricity production in the U.S. within 10 years, replacing them with alternatives such as solar, wind, and geothermal power, conservation, and clean-coal technology. He envisions nuclear power retaining its current share of domestic electricity generation, about 20 percent. Coal, which

[126]There exist numerous accounts of this proposal. See, for example, Brendan Smialowski, "Gore Urges Change to Dodge an Energy Crisis," *New York Times*, July 18, 2008; Bryan Walsh, "Gore's Bold, Unrealistic Plan to Save the Planet," *Time*, July 18, 2008.

currently produces about half of American electricity, would be drastically reduced or eliminated, while renewable sources, now producing less than three percent of the nation's electricity, would increase rapidly.

Specifying the Alternatives

As noted, the proposal, while recommending a "100 percent carbon free electricity sector by 2020," was short on specifics. For example:

- While consideration was initially given to the necessity for clean coal and CCS, virtually all follow-up discussion focused on the need to transition from coal to renewables
- Similarly, while accepting the need for the current nuclear fleet, Mr. Gore did not advocate building any new nuclear plants.
- Natural gas and petroleum electric generation were hardly mentioned at all.
- The need for energy efficiency and electric cars was noted, but no specifics were provided
- Similarly, while emphasizing the need for a phenomenal increase in renewable electricity generation, no specifics were given on how this is to be disaggregated among solar thermal, PV, wind, geothermal, biomass, etc.

Several simulations of the likely economic and jobs impact in 2020 of the proposal were conducted here. All of the simulations utilized the methodological tool and spreadsheet discussed in Section IV and utilized 2020 forecast data for all parameters. These data were derived from EIA forecast studies and the other sources discussed in previous sections.

2020 Decarbonization Scenario I

This scenario:

- Zeroed out coal electricity generation in 2020
- Held nuclear, natural gas, and petroleum to their EIA reference case 2020 forecast levels
- Distributed the EIA reference case 2020 coal-based electricity generation among the renewable sources

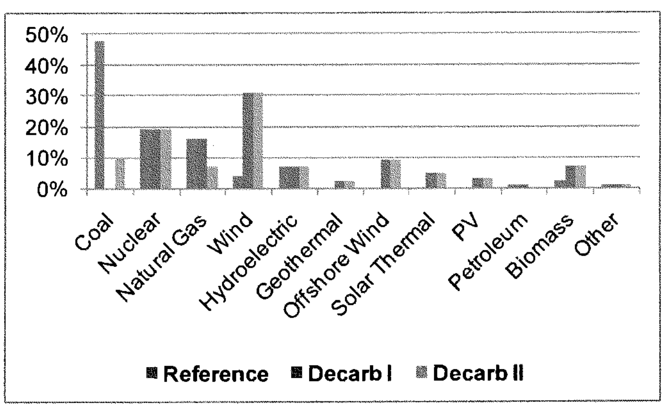
Thus, basically, this scenario transferred all forecast coal electricity generation in 2020 to renewable sources – Table V-5 and Figure V-2.

Table V-5
2020 Decarbonization Scenario I Parameters

	Consumption		Est.Price
Electric Power Sector, 2020 Decarbonization Scenario	Tbtu	Percent	c/kWh
Coal	0.0	0%	7.0
Nuclear	8.8	19%	10.2
Natural Gas	7.1	16%	8.5
Wind	14.0	31%	13.9
Other	15.7	34%	18.0
Hydroelectric	*3.0*	*7%*	11.2
Geothermal	*1.0*	*2%*	10.0
Offshore Wind	*4.0*	*9%*	22.0
Solar Thermal	*2.1*	*5%*	24.7
PV	*1.5*	*3%*	37.0
Petroleum	*0.6*	*1%*	14.0
Biomass	*3.0*	*7%*	10.3
Other	*0.5*	*1%*	9.0
Total	45.6	100.0%	
Calculated average price of electricity (cents/kWh)			13.76
2020 reference price of electricity (cents/kWh)			9.30

Source: Management Information Services, Inc., 2009.

Figure V-2
Redistribution of U.S. 2020 Electricity Generation Under the Decarbonization Scenarios



Source: Management Information Services, Inc., 2009.

As expected, and as shown in Table V-8, the impact on 2020 GDP and jobs of this scenario is significant:

- Average electricity prices increase nearly 50 percent
- GDP is about $740 billion (2007 dollars) lower – nearly five percent
- The job loss is 6.3 million – about four percent.

2020 Decarbonization Scenario II

This scenario attempted to be somewhat more realistic in interpreting the proposal. It assumed that both coal and natural gas – but not petroleum – would remain major contributors to 2020 electricity generation. However, their contributions are now much smaller than in the EIA reference forecast and their costs are significantly higher due to the mandatory CCS requirements. The relative contributions of the renewable technologies remain about the same as in Scenario I – see Table V-6 and Figure V-2. Specifically, Scenario II:

- Zeroed out petroleum electricity generation in 2020
- Held nuclear to its EIA reference case 2020 forecast level
- Reduced coal generation to 20 percent of its 2020 forecast level and included CCS costs
- Reduced natural gas generation to 50 percent of its 2020 forecast level and included CCS costs[127]

[127]Specifically, in this scenario in 2020: Coal generation is reduced from 22 tbtu to 4.4 tbu, nuclear generation remains unchanged at 8.8 tbtu, natural gas generatioin decreases from 7.1 tbtu to 3.3 tbu, and renewable generation increases from 7.1 tbtu to 28.6 tbtu.

Table V-6
2020 Decarbonization Scenario II Parameters

Electric Power Sector, 2020 Decarbonization Scenario	Consumption Tbtu	Consumption Percent	Est.Price c/kWh
Coal with CCS	4.4	10%	11.4
Nuclear	8.8	19%	10.2
Natural Gas with CCS	3.3	7%	11.4
Wind	14.0	31%	13.9
Other	15.1	33%	18.2
Hydroelectric	*3.0*	*7%*	11.2
Geothermal	*1.0*	*2%*	10.0
Offshore Wind	*4.0*	*9%*	22.0
Solar Thermal	*2.1*	*5%*	24.7
PV	*1.5*	*3%*	37.0
Petroleum	*0.0*	*0%*	14.0
Biomass	*3.0*	*7%*	10.3
Other	*0.5*	*1%*	10.0
Total	45.6	100.0%	
Calculated average price of electricity (cents/kWh)			14.19
2020 reference price of electricity (cents/kWh)			9.30

Source: Management Information Services, Inc., 2009.

As shown in Table V-8, the impact on 2020 GDP and jobs of this scenario is somewhat more significant than under scenario I:

- Average electricity prices increase more than 50 percent
- GDP is about $810 billion (2007 dollars) lower – about 5.3 percent
- The job loss is 6.9 million – about 4.4 percent.

2020 Decarbonization Scenario III

As discussed, in Section II.D, there are concerns about the actual current and forecast LCOE of renewables, and RE is the main focus of the Decarbonization proposal. Accordingly, this scenario increased the 2020 LCOEs of wind, PV, and solar thermal by 33 percent but held the relative distribution of electricity generation among all technologies the same as under Scenario II, as shown in Table V-4 and Figure V-2.

Table V-7
2020 Decarbonization Scenario III Parameters

	Consumption		Est.Price
Electric Power Sector, 2020 Decarbonization Scenario	Tbtu	Percent	c/kWh
Coal with CCS	4.4	10%	11.4
Nuclear	8.8	19%	10.2
Natural Gas with CCS	3.3	7%	11.4
Onshore Wind	14.0	31%	18.5
Other	15.1	33%	22.5
Hydroelectric	*3.0*	*7%*	11.2
Geothermal	*1.0*	*2%*	10.0
Offshore Wind	*4.0*	*9%*	29.3
Solar Thermal	*2.1*	*5%*	32.9
PV	*1.5*	*3%*	49.3
Petroleum	*0.0*	*0%*	14.0
Biomass	*3.0*	*7%*	10.3
Other	*0.5*	*1%*	10.0
Total	45.6	100.0%	
Calculated average price of electricity (cents/kWh)			17.02
2020 reference price of electricity (cents/kWh)			9.30

Source: Management Information Services, Inc., 2009.

As shown in Table V-8, the impact on 2020 GDP and jobs is significantly higher than under scenarios I or II:

- Average electricity prices increase 83 percent
- GDP is nearly 1.3 trillion (2007 dollars) lower – about 8.4 percent
- The job loss is nearly 11 million – about seven percent.

Table V-8
Summary of the 2020 Impacts of the Decarbonization Scenarios

	Scenario I		Scenario II		Scenario III	
	Change	Percent	Change	Percent	Change	Percent
Electricity prices (¢/kWh)	+4.5¢	+48	+4.9¢	+53%	+7.7¢	+83%
GDP (billion 2007$)	-$739	-5%	-$810	-5.3%	-$1,280	-8.4%
Jobs (thousands)	-6,300	-4%	-6,900	-4.4%	-10,900	-7%

Source: Management Information Services, Inc., 2009.

Thus, the economic and jobs impacts of the 2020 decarbonization proposal are likely to be severe:

- Average electricity prices could increase by 50 – 80+ percent
- GDP could be reduced by $700 billion to nearly $1.3 trillion (2007 dollars) lower – about 5 to 8.4 percent
- Job losses could total 6.3 million to nearly 11 million – about four to seven percent.

To put these losses into perspective, through August of 2009, the worst economic and financial recession in 75 years has resulted in total U.S. job losses of about 6.9 million.[128]

No attempt was made here to estimate the potential cost of the decarbonization proposal. However, a recent study by J.P. Morgan estimated that the potential costs of achieving a 15 percent renewable electricity standard by 2020 range between about $160 billion and $450 billion.[129] The 2020 decarbonization proposal would result in between 60 and 70 percent of U.S. electricity in 2020 being generated by renewables, and the cost to achieve this is thus likely to range between about $650 - $1,800 billion to $750 -$2,100 billion. Using the mean estimates, it is likely that the proposal may cost $1.2 to $1.4 trillion.[130]

[128]As Alan Greenspan noted in his memoir, "Cap-and-trade systems or carbon taxes are likely to be popular only until real people lose real jobs as their consequence." Alan Greenspan, *The Age of Turbulence*, Penguin, 2007.

[129]Christopher Blansett, *The Proposed Renewable Electricity Standard and its Impact on the Growth Rate of the Renewable Energy Sector*, J.P. Morgan Securities, Inc., September 2009.

[130]To put these costs in perspective, the electricity generation CAPEX for the top 45 utilities in the U.S., who generate the bulk of the nation's power, was well under $30 billion in 2008.

V.C. Assessment of the EIA Analysis of the Lieberman-Warner Bill

In April 2008, EIA issued a report in response to a request from Senators Lieberman and Warner for an analysis of S. 2191, the Lieberman-Warner (L-W) Climate Security Act of 2007, a complex bill regulating emissions GHGs through market-based mechanisms, energy efficiency programs, and economic incentives.[131] To analyze the provisions of S. 2191, several alternative cases were prepared:

- The S. 2191 Core Case assumed that key low-emissions technologies, including nuclear, fossil with CCS, and various renewables, are deployed in a timeframe consistent with the emissions reduction requirements.
- The S. 2191 No International Offsets Case, is similar to the S. 2191 Core Case, but assumed that use of international offsets is limited.
- The S. 2191 High Cost Case is similar to the S.2191 Core Case except that the costs of nuclear, coal with CCS, and biomass are assumed to be 50 percent higher than in the Core Case.
- The S. 2191 Limited Alternatives Case assumes the deployment of key technologies, including nuclear, fossil with CCS, and various renewables, is held to their Reference Case level through 2030, as are imports of LNG.

EIA's key findings included the following:

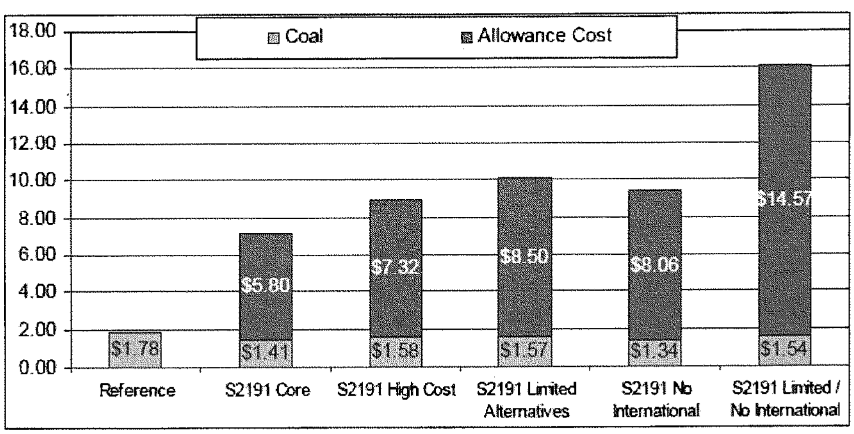
- S. 2191 significantly reduces projected GHG emissions compared to the Reference Case. Projected covered emissions in the S. 2191 cases, net of offsets, are 27 percent to 36 percent lower in 2020 and 45 percent to 56 percent lower in 2030.
- The electric power sector accounts for most of the emissions reductions, with new nuclear, renewable, and fossil plants with CCS serving as the key compliance technologies. Electric power accounts for 82 - 87 percent of energy-related CO_2 emissions reductions in 2020 and 82 - 92 percent of such reductions in 2030.
- If new nuclear, renewable, and fossil plants with CCS are not deployed rapidly enough, covered entities are projected to turn to increased natural gas use to offset reductions in coal generation, resulting in markedly higher delivered prices of natural gas.
- Emissions reductions in the residential, commercial, industrial, and transportation sectors are small relative to those in the electric power sector, and energy price increases are not large enough to induce consumers to make large changes in their energy use.
- Coal consumption is significantly reduced, and total coal consumption in 2030 ranges between 62 and 89 percent below the

[131] U.S. Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01, April 2008.

Reference Case level, and coal costs to electricity generators increase by a factor of 5-to-10 – Figure V-3.

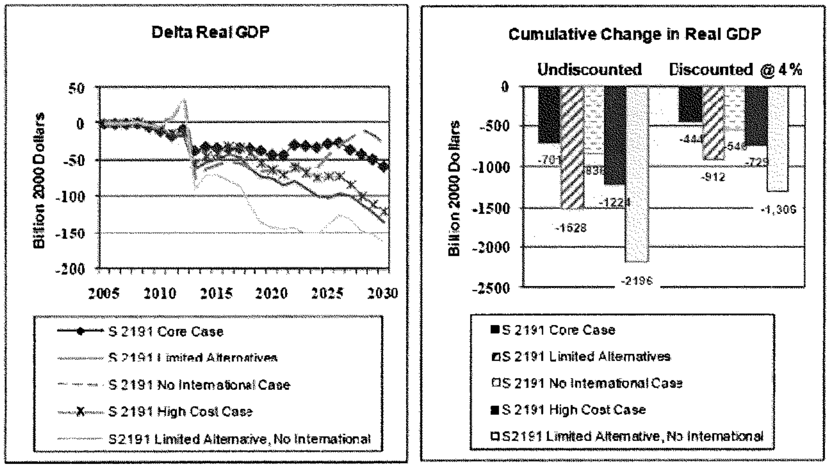
- GHG allowance prices are sensitive to the cost and availability of low-carbon generating technologies and emissions offsets. Estimated allowance prices range from $30 to $76/mtCO$_2$e in 2020 and from $61 to $156/mtCO$_2$e in 2030.
- S. 2191 increases energy prices and energy bills for consumers. Relative to the Reference Case, the price of using coal for power generation is 161 - 413 percent higher in 2020 and 305 - 804 percent higher in 2030. The price of electricity is 5 - 27 percent higher in 2020 and 11 - 64 percent higher in 2030. Under S. 2191, average annual household energy bills, excluding transportation costs, are $30 - $325 higher in 2020 and $76 - $723 higher in 2030.
- S. 2191 increases the cost of using energy, which reduces real economic output, reduces purchasing power, and lowers aggregate demand, and GDP falls relative to the Reference Case. Adverse economic impacts increase over time, and discounted GDP losses, 2009 – 2030, range from $444 billion (-0.2 percent) to $1,308 billion (-0.6 percent) -- Table V-9 and Figure V-4.
- S. 2191 impacts industrial activity, including manufacturing, to a greater extent than the overall economy. Industrial shipments in 2030 are reduced by $233 - $589 billion (-2.9 to -7.4 percent).

Figure V-3
Coal Costs to Electricity Generators
(2006 dollars per million Btu)



Source: U.S. Energy Information Administration, 2008.

Figure V-4
Real GDP Impacts, Change from Reference Case



Source: U.S. Energy Information Administration, 2008.

Table V-9
Macroeconomic Impacts of S. 2191 Cases and S. 1766 Update Cases
(billion 2000 dollars, except where noted)

	S. 2191 Cases					
	Core	High Cost	Limited Alternatives	No International Offsets	Limited Alternatives No International	S1766 Update
Cumulative Real Impacts 2009-2030 (Present Value using 4% Discount Rate)						
GDP						
Change	(444)	(729)	(912)	(546)	(1,306)	(66)
Percent Change	-0.2%	-0.3%	-0.4%	-0.2%	-0.6%	-0.03%
Consumption						
Change	(558)	(785)	(946)	(780)	(1,422)	(145)
Percent Change	-0.3%	-0.5%	-0.6%	-0.5%	-0.9%	-0.1%
Industrial Shipments (excludes services)						
Change	(1,340)	(1,723)	(2,031)	(2,430)	(3,684)	(722)
Percent Change	-1.3%	-1.7%	-2.0%	-2.4%	-3.6%	-0.7%
Nominal Revenue collected 2012-2030[a]	2,851	3,650	4,282	4,416	7,659	987

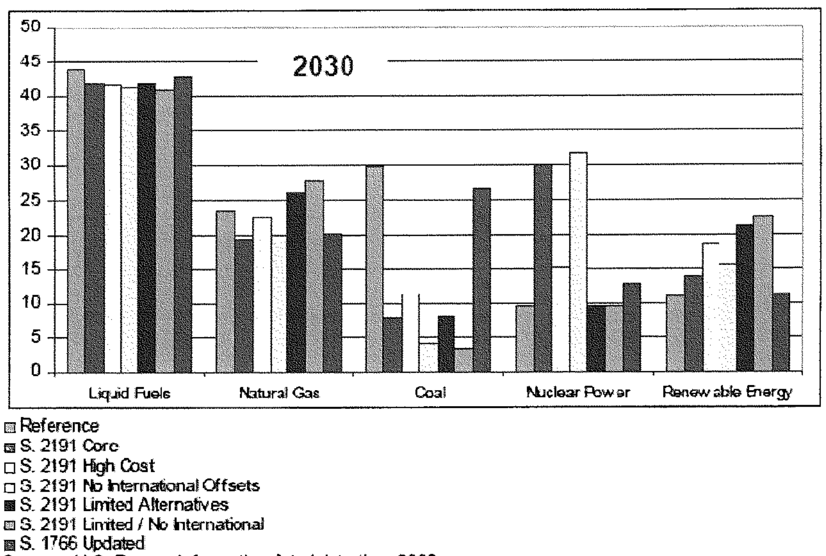
Source: U.S. Energy Information Administration, 2008.

As shown in Figure V-5, a major impact of the L-W bill would be a massive shift away from coal for electricity generation and massive increases in nuclear generation and, to a lesser extent, renewables.

Analysis of the EIA L-W Forecasts

The objective here was to assess the feedback between economic parameters and job impacts captured within the EIA analytical tools. The first step was to develop a 2030 set of reference parameters based on the EIA L-W analysis and the research discussed previously – Table V-10. It should be noted here that, to perform a credible comparative analysis, the 2030 forecast data are based primarily on those in the April 2008 EIA report, not on the April 2009 AEO 2009 (ARRA).[132] The EIA report, in turn, was based in large part on AEO 2007.[133]

Figure V-5
Total Energy Consumption by Source
(quadrillion Btu)



Source: U.S. Energy Information Administration, 2008.

[132]Valid comparisons of previous forecasts require that the data available at the time of the original forecast be used in the evaluation – see the discussion in Roger Bezdek and Robert Wendling, "A Half Century of Long-Range Energy Forecasts: Errors Made, Lessons Learned, and Implications For Forecasting," *Journal of Fusion Energy*, Vol. 21. No. 3/4 (December 2003), pp. 155-172.

[133]"In large part" because some of the estimates in the EIA analysis did not adhere to those published in *AEO 2007*; rather, they were apparently based on preliminary *AEO 2008* estimates.

The methodology and tool developed here were used to conduct a comparative analysis of two of the EIA cases:

- The S. 2191 No International Offsets Case
- The S. 2191 High Cost Case

Table V-10
2030 EIA L-W Reference Case

Electric Power Sector, 2030 EIA L-W Reference Case	Consumption Tbtu	Consumption Percent	Est.Price c/kWh
Coal	28.4	55%	7.2
Nuclear	9.2	18%	11.0
Natural Gas	7.4	14%	10.0
Wind	1.0	2%	14.0
Other	6.0	12%	11.5
Hydroelectric	*3.1*	*6%*	10.0
Geothermal	*0.2*	*0%*	10.0
Offshore Wind	*0.1*	*0%*	19.0
Solar Thermal	*0.1*	*0%*	19.0
PV	*0.1*	*0%*	27.0
Petroleum	*0.8*	*2%*	17.0
Biomass	*0.9*	*2%*	10.0
Other	*0.7*	*1%*	10.0
Total	52.0	100.0%	
Calculated average price of electricity (cents/kWh)			8.90
2030 EIA L-W reference price of electricity			8.90

Source: U.S. Energy Information Administration and Management Information Services, Inc., 2009.

The No International Offsets Case Comparison

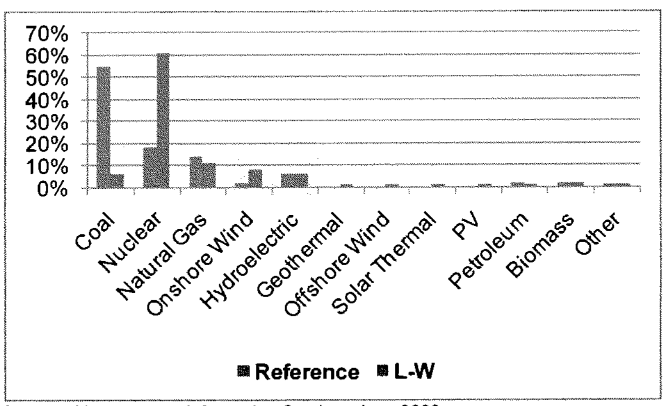
Table V-11 and Figure V-6 show the No International Offsets Case parameters.

Table V-11
MISI No international offset Case Estimate of L-W Parameters

Electric Power Sector, 2030 EIA L-W Case – MISI Estimate	Consumption		Est.Price
	Tbtu	Percent	c/kWh
Coal	3.1	6%	7.2
Nuclear	30.4	61%	11.0
Natural Gas	5.3	11%	10.0
Wind	4.0	8%	14.0
Other	6.8	14%	12.5
Hydroelectric	*3.1*	*6%*	10.0
Geothermal	*0.4*	*1%*	10.0
Offshore Wind	*0.6*	*1%*	19.0
Solar Thermal	*0.4*	*1%*	19.0
PV	*0.3*	*1%*	27.0
Petroleum	*0.4*	*1%*	17.0
Biomass	*1.1*	*2%*	10.0
Other	*0.5*	*1%*	10.0
Total	49.6	100.0%	
Calculated average price of electricity (cents/kWh)			11.10
2030 EIA L-W reference price of electricity			8.90

Source: Management Information Services, Inc., 2009.

Figure V-6
Changes in 2030 Electricity Generation



Source: Management Information Services, Inc., 2009.

The estimates derived here of the likely economic and jobs impact of the No International Offsets Case were compared with those reported by EIA. The findings are summarized in Table V-13. Specifically, in 2030:

- EIA estimated that electricity prices would increase by 2 ¢/kWh (22 percent), while here it was estimated that electricity prices would increase by 2.2 ¢/kWh (25 percent)
- EIA estimated that GDP would decrease by $32 billion (0.13 percent, while here it was estimated that GDP would decrease by about $590 billion (2.5 percent)
- EIA did not develop jobs estimates. The EIA estimate of GDP losses was translated into job losses using the GDP/jobs ratio developed in the tool.[134] This indicated that the EIA estimate of jobs losses is about 223,000 (-0.13 percent). Here it was estimated that the job loss is 4.1 million (2.4 percent)

The High Cost Case Comparison

Table V-12 and Figure V-6 show the High Cost Case parameters.

Table V-12
MISI High Cost Parameters

Electric Power Sector, 2030 EIA L-W Case – MISI High Cost Estimate	Consumption		Est.Price
	Tbtu	Percent	c/kWh
Coal	3.1	6%	7.2
Nuclear	30.4	61%	13.0
Natural Gas	5.3	11%	10.0
Wind	4.0	8%	18.6
Other	6.8	14%	13.8
Hydroelectric	*3.1*	*6%*	10.0
Geothermal	*0.4*	*1%*	10.0
Offshore Wind	*0.6*	*1%*	25.3
Solar Thermal	*0.4*	*1%*	25.3
PV	*0.3*	*1%*	35.9
Petroleum	*0.4*	*1%*	17.0
Biomass	*1.1*	*2%*	10.0
Other	*0.5*	*1%*	10.0
Total	49.6	100.0%	
Calculated average price of electricity (cents/kWh)			12.88
2030 EIA L-W reference price of electricity			8.90

Source: Management Information Services, Inc., 2009.

[134]As discussed in Chapter IV, in 2030, $1 billion (2007 dollars) in GDP generates 6,965 jobs. This estimate was used to translate the EIA projection of GDP losses into job losses.

The estimates derived here of the likely economic and jobs impact of the High Cost Case were compared with those reported by EIA. The distribution of electric generation remains the same as in the No International Offset Case (Figure V-6). The findings are summarized in Table V-13. Specifically, in 2030:

- EIA estimated that electricity prices would increase by 3¢/kWh (34 percent), while here it was estimated that electricity prices would increase by 4¢/kWh (45 percent)
- EIA estimated that GDP would decrease by $238 billion (one percent, while here it was estimated that GDP would decrease by about $1.1 trillion billion (4.5 percent)
- EIA did not develop jobs estimates. The EIA estimate of GDP losses was translated into job losses using the GDP/jobs ratio developed in the tool. This indicated that the EIA estimate of jobs losses is about 1.66 million (one percent). The job loss estimated here is 7.4 million (4.2 percent)

Table V-13
Summary Results of the EIA and MISI L-W Scenarios

	No International Offset Case				**High Cost Case**			
	EIA		**MISI**		**EIA**		**MISI**	
	Change	Percent	Change	Percent	Change	Percent	Change	Percent
Electricity prices (¢/kWh)	+2¢	+22%	+2.2¢	+25%	+3¢	34%	+4¢	45%
GDP (billion 2007$)	-$32	-0.13%	-$589	-2.5%	-$238	-1%	-$1,064	-4.5%
Jobs (thousands)	223*	-0.13%	-4,100	-2.4%	1,660*	-1%	-7,400	-4.2%
Implied elasticity of GDP with respect to electricity price	- 0.002		-0.1		-0.0.3		-0.1	

*MISI estimate
Source: Management Information Services, Inc., 2009.

Thus, using the methodology and tool developed here indicates that:

- The increase in electricity prices under both EIA scenarios analyzed would be somewhat higher than estimated by EIA.
- The GDP and jobs losses under both EIA scenarios analyzed would be much higher than estimated by EIA.
- The EIA methodology and NEMS implicitly assumes that increased electricity prices have relatively little impact on GDP or jobs.

The lack of impact in the EIA report of electricity prices on GDP or jobs is especially interesting and difficult to reconcile with decades of results reported in the literature. While the elasticity estimate used here of -0.1 can be assessed and modified, the implication in the EIA No International Offset Case that the elasticity estimate is virtually 0 is notable and indicates a need for further research

V.D. Assessment of the High Macro $30 Carbon Tax Case

Here, the objective was to analyze the results of the NEMS High Macro $30 carbon tax case (analyzed in prior research[135]) to obtain insight into the level of feedback to GDP that may be captured by NEMS. The NEMS High Macro $30 carbon tax case uses updated cost and performance of advanced coal-fired power plants under the assumption that all Fossil Energy R&D goals are met. A carbon tax of $30/ton carbon dioxide is instituted in 2012 and rises at a five percent annual rate. Retrofit and refurbishments capability are included, with cost reductions based on R&D assumptions.

Table V-14 shows forecasts of selected energy and economic variables that are the results of the High Macro $30 carbon tax case from the NEMS run. The production of coal is forecast to decline from 23.4 Quads in 2010 to 20.33 Quads in 2030, decreasing at an average annual compounded rate of -0.7 percent. At the same time, coal use in the electric generating sector is forecast to decrease -0.8 percent per year, in sharp contrast to the average forecast growth in electricity generation of 1.0 percent. The average delivered price of coal is also forecast to increase substantially over the period, rising from 1.94 $/MMBTU (2007 constant dollars) in 2010 to $8.83/MMBTU in 2030, an annual average increase of 7.9 percent.

Over the period, coal and natural gas inputs to electric generation will continue to decline drastically and will be replaced by a 90 percent increase in nuclear power and more than a doubling in the use of renewable fuel sources. By 2030, the forecast shows that renewable sources will account for just over 22 percent of total electricity generated and coal will decrease to 34 percent. The average price of electricity is forecast to rise sharply over the period, increasing 2.3 percent per year above the rise in overall inflation. The NEMS forecast shows a rise in the weighted average price of electricity going from 8.3¢/kWh in 2010 to 13.1¢/kWh in 2030. This is the highest increases seen in the various scenarios examined in the course of the MISI research.[136]

Table V-14 raises some questions about the NEMS-generated results. For example, the High Macro case represents a major shift away from coal and NG and in favor of nuclear power and renewables. Accordingly, electricity prices in 2030 are 34 percent higher than in the ARRA reference case. However, using the distribution of

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[135]NETL, *Development of an Economic and Job Impacts Analysis Tool and Technology Deployment Scenario Analysis*, DOE/NETL-402/092309, September 23, 2009. The High Macro $30 Carbon Tax Case here corresponds to the Repower and Retrofit Case in the September 23 paper.
[136]Ibid.

electric generating capacity among the options shown in Table V-14, the EIA NEMS estimates of LCOEs given in Table II-4, and the tool spreadsheet demonstrates that – using EIA's own data – electric prices cannot increase nearly that much in 2030.[137]

Second, Table V-14 shows that NEMS is forecasting that real GDP will increase 3.3 percent annually, 2010 through 2030. For the U.S., this is a high real 20-year real growth rate. Further, is it realistic to believe that GDP can grow at this rate when, as shown in the table, total electricity consumption is growing at only one percent annually over the same period?

Third, the table forecasts a very large growth in U.S. exports over the period, increasing from 11 percent of GDP in 2010 to 25 percent in 2030 – increasing 7.3 percent annually, and by the latter year the U.S. has an export surplus of nearly $700 billion (2007 dollars). Is this reasonable – especially when electricity consumption is increasing only one percent annually?[138]

Finally this table indicates that under the high macro case, real U.S. 2030 GDP will be 12 percent higher ($6.3 trillion in 2007 dollars) than under the ARRA reference case – Table V-15. Is this consistent with the fact that electricity prices under the high macro case are 34 percent higher than under the ARRA reference case? This indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is positive: Increased electricity prices increase GDP. Accepting the NEMS results at face value indicates an elasticity of about +0.28, e.g., a 12 percent increase in real GDP is associated with a 34 percent increase in electricity prices.

Not only is a positive elasticity contrary to studies in the literature, it also differs from the results derived using the MISI tool. Using this tool, the distribution of electricity consumption among the generation options, their associate LCOEs, and the tool-estimated elasticity indicates that under the High Macro case, U.S. GDP in 2030 should be about $800 billion (2007 dollars) lower than under the ARRA reference case – not $6.3 trillion higher. Thus, the net difference between the High Macro 2030 case and the tool-derived estimate is a GDP value of about $7.1 trillion (2007 dollars).[139]

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[137]This holds true for any reasonable simulations using weighted actual LCOE estimates for 2007 and the EIA forecast LCOEs for 2020 and 2030.

[138]These issues are discussed further in Management Information Services, Inc., "Implications of Recent EIA Forecasts For Energy and Electricity Demand," discussion paper prepared for NETL, July 2009.

[139]While a detailed analysis of NEMS is outside the scope of the current study, researchers have found evidence of systematic errors in NEMS' forecasts. For example, based on analysis of the EIA's 22 year projection record, RFF found a persistent tendency by NEMS to underestimate total energy demand by an average of two percent per year. For 14 individual fuels/consuming sectors there was significant directional consistency in the errors over time, ranging up to seven percent annually. Electric utility renewables, electric utility natural gas, transportation distillate, and residential electricity showed significant biases, and projections for certain other sectors have significant unexplained errors. See Carolyn Fischer, Evan Herrnstadt, and Richard Morgenstern, "Understanding Errors in EIA Projections of Energy Demand," Resources for the Future paper RFF DP 07-54, November 2008.

Table V-14
High Macro $30 Carbon Tax Case -- Selected NEMS Output Indicators

	2010	2020	2030	AAC '10-30
Production				
Coal (Quadrillion btu's)	23.4	20.94	20.22	-0.7%
Electricity Generated by Fuel (billion killowatthours)				
Coal	2,030	1,807	1,737	-0.8%
Natural Gas	778	777	594	-1.3%
Nuclear Power	809	940	1,530	3.2%
Renewable Sources	473	843	1,134	4.5%
Other	88	75	76	-0.7%
Total	4,179	4,442	5,071	1.0%
Electricity Sales by Sector (billion killowatthours)				
Residential	1,409	1,413	1,604	0.7%
Commercial	1,407	1,562	1,833	1.3%
Industrial and Other	1,104	1,262	1,393	1.2%
Total	3,920	4,237	4,830	1.0%
Prices (2007$)				
Coal				
Avergage Delivered Price ($ per million btu's)	1.94	6.18	8.83	7.9%
Electricity (per killowatthour)				
Residential	9.7	14.3	15.2	2.3%
Commercial	8.5	12.7	13.3	2.3%
Industrial and Other	5.8	9.1	9.4	2.4%
Average Price (cents per kilowatthour)	8.3	12.3	13.1	2.3%
Value of Electric Power Sector (billion 2007$)				
Residential	136.7	202.1	243.8	2.9%
Commercial	119.6	198.4	243.8	3.6%
Industrial and Other	64.0	114.8	130.9	3.6%
Total Value of Coal Industry (billion 2007$)	45.4	129.4	178.5	7.1%
Total Value of Electric Power Sector (billion 2007$)	325.4	521.2	632.7	3.4%
Real GDP (billion 2000$)	11,912	16,509	22,610	3.3%
Real Consumption	8,554	11,499	15,725	3.1%
Real Investment	1,607	2,938	4,388	5.2%
Real Government Spending	2,149	2,373	2,788	1.3%
Real Exports	1,372	3,075	5,564	7.3%
Real Imports	-1,829	-3,053	-4,996	5.2%
Change in Inventories as % of GDP Components	0.5%	-1.9%	-3.7%	-

Source: NEMS Output Tables, 30_5_FE_RR_all, Repower and Retrofit Case, U.S. Department of Energy, July 2009; and MISI, 2009.

Table V-15
Impact of High Macro $30 Carbon Tax Case
Compared to ARRA Reference Case

	2010	2020	2030
Gross Output (billion '07$)	736	2,520	6,260
Employment (thosands)	4,223	13,074	32,586
Personal Income (billion '07$)	332	1,090	2,701
Government Tax Receipts (billion '07$)	132	436	1,077

Source: Management Information Services, Inc., 2009.

Applying the job estimation methodology, in 2030 the High Macro case generates 32.6 million more jobs than the ARRA reference case. However, the tool developed here estimates that the High Macro case will actually generate 5.6 million fewer jobs than the ARRA reference case in 2030. Thus the net job difference between the two estimates is about 40 million jobs.

V.E. Assessment of the High Renewables-based Power Case

The objective here was to analyze the results of the NEMS High Renewables-based Power case (prior analysis[140]) to obtain insight into the level of feedback to GDP that may be captured by NEMS. The High Renewables-Based Power Scenario documented in the September 2009 report was derived from an analysis of a 25-percent Federal renewable electricity standard completed at the request of Congressman Edward Markey.[141]

Table V-16 shows the forecasts of selected energy and economic variables that are the results of the High Renewables-based Power case NEMS run.[142] The production of coal is forecast to increase from 23.27 Quads in 2010 to 23.48 Quads in 2020, but then decline to 23.15 Quads in 2030. At the same time, coal use in the electric generating sector is forecast to increase 0.1 percent per year, much lower than the average forecasted growth in electricity generation of 1.0 percent. The average delivered price of coal is forecast to also increase slightly over the period, rising from 1.93 dollars per MMBTU's (2007 constant dollars) to 2.01 dollars per MMBTU's in 2030 -- a 0.2 percent annual increase.

Over the period, coal inputs to electric generation will continue to rise until 2020 and then fall through 2030. Any potential coal expansion that was forecast will be replaced by a massive deployment of renewable energy sources, which are forecast to

[140]NETL, *Development of an Economic and Job Impacts Analysis Tool and Technology Deployment Scenario Analysis*, op. cit. The High Renewables-based Power case here corresponds to the 25-Percent Renewable Electricity Standard Case in the September 23 paper.
[141]Much of this information is taken from: *Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act Discussion Draft.* SR/OIAF/2009-04, U.S. Department of Energy, April 2009.
[142]NEMS run waxrpsne-75.d051309e.

increase nearly five percent annually over the 20-year period. By 2030 the forecast shows that renewable sources will account for almost 25 percent of total electricity generated. Renewable fuels will account for 50 percent more electricity generated than natural gas plants and 50 percent more electricity generated than the entire U.S. nuclear fleet. However, while this overwhelming and rapid change in the mix in the "input fuels" of electric generation is taking place over the 20-year period, the average price of electricity is forecast to rise only one percent per year above the rise in overall inflation. The EIA forecast shows a rise in the weighted average price of electricity going from 8.3¢/kWh in 2010 to 10.1¢/kWh in 2030. These are identical increases to that shown in the updated AEO case (ARRA).

Table V-16
High Renewables Case - Selected Indicators

	2010	2020	2030	AAC '10-30
Production				
Coal (Quadrillion btu's)	23.27	23.48	23.15	0.0%
Electricity Generated by Fuel (billion killowatthours)				
Coal	2,020	2,092	2,054	0.1%
Natural Gas	771	671	827	0.4%
Nuclear Power	809	869	858	0.3%
Renewable Sources	467	861	1,213	4.9%
Other	87	78	79	-0.5%
Total	4,155	4,571	5,031	1.0%
Electricity Sales by Sector (billion killowatthours)				
Residential	1,402	1,476	1,650	0.8%
Commercial	1,402	1,621	1,850	1.4%
Industrial and Other	1,093	1,243	1,287	0.8%
Total	3,897	4,340	4,787	1.0%
Prices (2007$)				
Coal				
Avergage Delivered Price ($ per million btu's)	1.93	2.00	2.01	0.2%
Electricity (per killowatthour)				
Residential	9.8	11.1	11.8	0.9%
Commercial	8.5	9.4	10.2	0.9%
Industrial and Other	5.8	6.5	7.2	1.1%
Average Price (cents per kilowatthour)	8.3	9.3	10.1	1.0%
Value of Electric Power Sector (billion 2007$)				
Residential	137.4	163.8	194.7	1.8%
Commercial	119.2	152.4	188.7	2.3%
Industrial and Other	63.4	80.8	92.7	1.9%
Total Value of Coal Industry (billion 2007$)	44.9	47.0	46.5	0.2%
Total Value of Electric Power Sector (billion 2007$)	323.5	403.6	483.5	2.0%
Real GDP (billion 2000$)	11,586	15,396	19,871	2.7%

Source: *Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act Discussion Draft.* SR/OIAF/2009-04, U.S. Department of Energy, April 2009.

Examination of Table V-16 indicates that the NEMS-generated results for this case differ from those of the High Macro case. For example, the High Renewables case represents a major shift away from coal in favor of renewables. Nevertheless, electricity prices in 2030 are only about three percent higher than in the ARRA reference case. Using the distribution of electric generating capacity among the options shown in Table V-16, the EIA NEMS estimates of LCOEs given in Table II-4, and the spreadsheet tool demonstrates that electricity prices in the High Renewables case should be somewhat higher – in the range of 10.5¢/kWh to 11¢/kWh, six to 12 percent. However, given the uncertainties inherent in any forecasts, it is not clear that these differences are statistically significant.

Table V-17
Impact of the High Renewables Case
Compared to ARRA Reference Case

	2010	2020	2030
Gross Output (billion '07$)	-29	-4	-9
Employment (thousands)	-161	-25	-43
Personal Income (billion '07$)	-13	-2	-4
Government Tax Receipts (billion '07$)	-6	-1	-2

Source: Management Information Services, Inc., 2009.

Second, Table V-16 shows that NEMS is forecasting that real GDP will increase 2.7 percent annually, 2010 through 2030. For the U.S., this would represent good economic performance, but something that, based on historical experience, may be achievable.

Finally, this table indicates that under the High Renewables case real U.S. 2030 GDP will be virtually identical to GDP under the ARRA reference case – Table V-17. This indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is essentially zero. This is contrary to studies in the literature but, given the small increase in electricity prices, it may not be significant

Using the tool developed here, the distribution of electricity consumption among the generation options, their associated LCOEs, and the tool-estimated elasticity indicates that under the High Renewables case:

- A three percent increase in electricity prices indicates that 2030 GDP should be about $70 billion less and that total jobs should be about 500,000 less than forecast using NEMS.
- Using the mean estimate of the tool-estimated electricity price forecasts, which is about 10 percent, indicates that 2030 GDP should be about $330 billion less and that total jobs should be about 1.6 million less than forecast using NEMS.

VI. FINDINGS AND IMPLICATIONS

VI.A. General Findings

First, the findings derived here indicate that energy and energy prices can affect GDP. Most economists who have analyzed the issue agree that there is a negative relationship between energy price changes and economic activity, but there are significant differences of opinion on the economic mechanisms through which price impacts are felt. Estimates of the impacts of oil shocks have produced different results, with smaller time-series econometric models producing energy price change-output elasticities of -2.5 percent to -11 percent, while large disaggregated macro models estimate smaller impacts – in the range of -0.2 percent to -1.0 percent.

For studies of the long-run impact of energy on the economy, analyses have been conducted by economists working in the area of "ecological economics" since mainstream, neoclassical economists have largely ignored the role of energy, or other raw materials, in the study of growth. Robert Solow is generally credited with beginning neoclassical growth analysis with his 1956 model that posited economic growth as the result of growing inputs of labor, capital, and "technological progress." Since then, the evolution of growth theory has generally focused on theoretical and empirical attempts to explain technological progress. Robert Ayres and Benjamin Warr, among others, have developed models that incorporate increasing energy use as a driver of economic growth.

Second, the findings here indicate that energy matters to the economy. While this seems to be an obvious truism, some recent literature on climate change mitigation implies that energy demand can be suppressed and energy prices can be increased, and that the impact will be increased economic and job growth. The overwhelming weight of the findings of studies conducted over the past four decades refutes this.

Energy is important: It performs work, and if less energy is used, then other inputs must be diverted to perform that work. Energy is complementary to capital and labor; with more energy, capital and labor are more productive. Thus, constraints on energy use negatively impact productivity and GDP, and the tighter the constraint the greater the effects.[143] Similarly, energy prices matter to the economy. While this also seems to be an obvious truism, some NEMS work seems to decouple the relationship between energy prices and economic activity. The findings derived here do not support this.

Third, contrary to common perception and much that has been written, the U.S. economy is still heavily dependent on energy, and energy and GDP are closely related. Energy consumption per dollar of GDP is declining in the U.S., and has been for decades as the economy becomes more energy efficient. Thus, more GDP is created

[143]See the discussion in Michael E. Canes, "Economic Modeling of Climate Policy Impacts," The Climate Policy Center, November 7, 2003.

per unit of energy consumed currently than previously. However, many analysts and policy-makers interpret this as implying that U.S. energy dependence is also declining when, in fact, the opposite is the case. Creating more GDP with a unit of energy does imply that the economy's efficiency is increasing and that it can, in fact, create more economic output with a given unit of energy. However, this also implies that the loss of a given unit of energy in the current U.S. economy is much more important than previously when the economy was not as efficient. Dependency can be measured by how much output can be created by a given energy input, and that makes the energy input all that more important.[144]

Fourth, energy quality is important: Technological change leads to the substitution of low-quality production factors by better quality factors of production, and this applies to energy as it does to other factors of production. From an economic standpoint, the quality of energy is reflected in its contribution to overall economic growth and to total factor (not just energy alone) productivity. When prices for higher-quality energy sources, such as electricity, increase it requires more lower-quality energy sources to substitute for it. Energy productivity improvement is a centuries-long trend, and Bashmakov has estimated that the global long-term sustainable average annual rate of energy productivity growth is 1.0-1.5 percent.[145] Similarly, Getts analyzed data from the Euro Area and found that the consumption of high quality forms of energy is highly correlated with GDP growth and that the use of inefficient energy sources leads to less growth.[146] Thus, the forced displacement of coal by lower quality, more costly, and less reliable energy sources, such as some renewables, may not be desirable.

Finally, four decades of research has shown that there is a quantifiable negative correlation between energy prices and GDP: Increased energy prices reduce GDP, and vice-versa. While there is controversy as to the size and characteristics of the relationship, there is little doubt that the correlation is negative and significant. At the same time, electricity is increasing in importance in the U.S. economy: In 2000 it provided 37 percent of U.S. energy consumption and by 2030 EIA forecasts that it will provide 43 percent. Thus, the impact of electricity and electricity prices on GDP and other economic variables will be gradually increasing over time.

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[144]See the discussion in Ron Oligney, op. cit.

[145]Thus, "When the share of energy costs grows, the rate of return drops, thus slowing down economic growth. Igor Bashmakov, "Three Laws of Energy Transitions," 38th Session of the International Seminars on Planetary Emergencies and Associated Events, Ettore Majorana International Foundation and Centre for Scientific Culture in Erice in collaboration with the World Federation of Scientists and the ICSC, August 2007.

[146]Justin T. Getts, "The Impacts of Energy Efficiency and Consumption on GDP in the Euro Area" Bryant University, Smithfield, RI, 2007.

VI.B. The Tool Developed Here

NEMS may not adequately capture the impacts on GDP of changes in energy costs, and a methodology and tool were developed here to explore this relationship. The tool quantifies the relationship between electricity prices and the economy and permits the estimation of the economic and jobs impacts of changes in energy-related assumptions and variables. It was developed on the basis of an extensive literature review and analysis of relevant studies, and produces results different than NEMS. It can be used to provide rough estimates of the impact of changes in electricity prices on economic variables such as GDP and jobs.

The tool is simple and straightforward, but the tool spreadsheet can get complex very quickly, and many additions to the tool and spreadsheet can be made. Parameters, variables, and assumptions in the current version that can be changed include forecast year, base year dollars, LCOEs of competing electricity generation options, energy prices, electricity generation shares, energy requirements, GDP, employment, productivity, elasticities, and others.

The tool can be expanded to be more realistic; for example, variations in the share of the generation options in the total electricity mix can be made endogenous with respect to energy prices, the relationship between the LCOEs of the different generation options and the likely rates of growth in the generation mix can be made endogenous, an endogenous CO_2 component could be added, an input-output component could be added, and numerous other improvements and extensions are possible. However, as more of these improvements and extensions are made, the tool begins to be transformed into an econometric model with appropriate feedback loops and interactions.

The tool can utilize data through 2030 on the distribution of electricity generation among the major technology options and the LCOE costs of each option. This information can be used to estimate overall U.S. electricity prices based on the share of generation accounted for each option in a specific year and the LCOE of that option that year. Further, given a forecast electricity price for a specific year, the tool can be used to "reverse engineer" the options to estimate the generation shares and LCOEs consisted with the forecast electricity price. This reverse engineering was used in the scenarios analyses to deconstruct NEMS forecast electricity prices.

The tool cannot compare to NEMS or similar large scale econometric models, and it is not designed to. However, it can offer valuable insights, and straightforward spreadsheet analysis can provide advantages in terms of cost, transparency, ease of use, and rapid turnaround over very large, complex models. Further, as Milton Friedman famously argued, any type of economic model should be judged on its predictive accuracy and not on its complexity or the resources that went into its development.[147] Thus, while NEMS may be preferred on the basis of its size and

[147]Milton Friedman, "A Review of Input-Output Analysis -- Comment" in *Input-Output Analysis: An Appraisal*, Studies in Income and Wealth, Vol. 18, National Bureau of Economic Research, 1955, pp. 169-

imbedded data bases, the tool developed here may, at least in some instances, generate more theoretically acceptable results.

VI.C. Findings from the Scenario Analyses

Five analyses were conducted using the methodology and tool to obtain insight into the level of feedback to GDP that may be captured by NEMS:

- 2010 Test Case Scenarios
- 2020 Decarbonization Scenarios
- Assessment of the EIA Analysis of the Lieberman-Warner Bill
- Assessment of the High Macro $30 carbon tax case (from Activity III)
- Assessment of the High Renewables-based Power case (from Activity III)

2010 Test Case Scenarios

Hypothetical test case scenarios were conducted to obtain an indication of the likely impact of substantially reducing U.S. coal-fired electricity generation in the near future and replacing it with natural gas and renewables. It was hypothesized that in 2010 coal-fired electricity generation is reduced by 25 percent and that half of the reduction is replaced by an increase in natural gas generation and half by increased renewables. The findings indicated that the 2010 economic and jobs impacts are significant and may result in:

- Average electricity prices increases of nearly 25 percent
- GDP reduction of $285 billion (2007 dollars) – 2.6 percent
- Job losses of 2.9 million – slightly more than two percent

2020 Decarbonization Scenarios

A proposal to transform the U.S. electricity grid to carbon-free energy within 10 years was analyzed, and several simulations were conducted of the likely economic and jobs impact in 2020 of the proposal. The findings indicated that the economic and jobs impacts of the 2020 decarbonization proposal may be severe:

- Average electricity prices could increase by 50 – 80+ percent
- GDP could be reduced by $700 billion to nearly $1.3 trillion (2007 dollars) – about five to over eight percent
- Job losses could total 6.3 million to nearly 11 million – about four to seven percent.

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173. There is also the principle of Occam's razor, which states that when there are two competing constructs for making predictions, the simpler one is usually preferred, and that explanation of any phenomenon should make as few assumptions as possible.

Assessment of the EIA Analysis of the Lieberman-Warner Bill

An assessment was made of the EIA projection of the economic impacts of the Lieberman-Warner Climate Security Act of 2007, which would regulate GHG emissions through market-based mechanisms. The objective was to assess the reasonableness of the EIA findings of the likely economic and jobs impact of LW, and the findings indicated that:

- The increase in electricity prices under the EIA scenarios analyzed would be somewhat higher than estimated by EIA.
- The GDP and jobs losses under the EIA scenarios analyzed would be much higher than estimated by EIA.
- The EIA methodology and NEMS implicitly assume that increased electricity prices have relatively little impact on GDP or jobs.

The lack of impact in the EIA report of electricity prices on GDP or jobs is difficult to reconcile with decades of results reported in the literature, and the implication in the EIA analysis that the elasticity estimate is virtually 0 is open to question. This is an important issue deserving of further research.

Assessment of the High Macro $30 Carbon Tax Case

The results of the NEMS High Macro $30 carbon tax case (from Activity III) were analyzed to obtain insight into the level of feedback to GDP that may be captured by NEMS. The analysis raised some questions about the NEMS-generated results. For example, the High Macro case represents a major shift away from coal and NG and in favor of nuclear power and renewables, and electricity prices in 2030 are 34 percent higher than in the ARRA reference case. However, using NEMS data, it is difficult to simulate electricity prices that high.

Second, NEMS is forecasting that real GDP will increase 3.3 percent annually, 2010 through 2030 – a rather high long term real growth rate, especially when total electricity consumption is growing at only one percent annually over the same period.

Third, NEMS forecasts a very large growth in U.S. exports over the period, increasing from 11 percent of GDP in 2010 to 25 percent in 2030 – increasing 7.3 percent annually, and by the latter year the U.S. has an export surplus of nearly $700 billion (2007 dollars). This is questionable – especially when electricity consumption is increasing only one percent annually.

Under the High Macro case, real U.S. 2030 GDP will be 12 percent higher ($6.3 trillion in 2007 dollars) than under the ARRA reference case, and this may not be consistent with the fact that electricity prices under the High Macro case are 34 percent higher than under the ARRA reference case. This also indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is actually positive:

Increased electricity prices increase GDP. This is contrary to results reported in the literature and differs from the results derived here using the tool

Assessment of the High Renewables-based Power Case

The results of the NEMS High Renewables-based Power case (from Activity III) were analyzed to obtain insight into the level of feedback to GDP that may be captured by NEMS. The analysis indicated that the NEMS-generated results for this case generated less variance than did the High Macro case. For example, the High Renewables case represents a major shift away from coal in favor of renewables, but electricity prices in 2030 are only about three percent higher than in the ARRA reference case. Using the NEMS data indicates that electricity prices should be somewhat higher – in the range of 10.5¢/kWh to 11¢/kWh, six to 12 percent. However, given the uncertainties inherent in any forecasts, it is not clear that these differences are statistically significant.

Second, NEMS is forecasting that real GDP will increase 2.7 percent annually, 2010 through 2030. For the U.S., this would represent good economic performance, but something that may be achievable.

Finally, under the High Renewables case, real U.S. 2030 GDP will be virtually identical to GDP under the ARRA reference case, which indicates that the NEMS model here implicitly assumes that the electricity price-GDP elasticity is zero. This is contrary to studies in the literature but, given the small increase in electricity prices it may not be significant

Using the tool indicates that under the High Renewables case:

- A three percent increase in electricity prices implies that 2030 GDP should be about $70 billion less and that total jobs should be about 500,000 less than forecast using NEMS.
- Using the mean estimate of the MISI electricity price forecasts indicates that 2030 GDP should be about $330 billion less and that total jobs should be about 1.6 million less than forecast using NEMS.

VI.D. Summary of Major Findings

The major findings of the research reported here are:

- Energy and energy prices affect GDP, and there is a negative relationship between energy price changes and economic activity.
- The U.S. economy is still heavily dependent on energy, and this dependency can be measured by how much output can be created by a given energy input.

- Electricity is increasing in importance in the U.S. economy and thus the impact of electricity and electricity prices on GDP and other economic variables will be gradually increasing over time.
- NEMS may not adequately capture the impacts on GDP of changes in energy costs, and a methodology and tool were developed here to explore this relationship. The tool quantifies the relationship between electricity prices and the economy and permits the estimation of the economic and jobs impacts of changes in energy-related assumptions and variables.
- The tool cannot compare to NEMS or similar large scale econometric models, but it can offer valuable insights and can provide advantages in terms of cost, transparency, ease of use, and rapid turnaround over very large, complex models.
- Analyses were conducted using the tool to obtain insight into the level of feedback to GDP that may be captured by NEMS, and these analyses indicated that:
  - The economic and jobs impacts of displacing coal generation could be significant in terms of electricity price increases, reduction in GDP, and job losses
  - Attempts to "decarbonize" electricity generation by 2020 may have severe impacts on the U.S. economy and job market
  - The EIA methodology and NEMS seem to imply that increased electricity prices have relatively little impact on GDP or jobs
  - NEMS may underestimate the impact of coal displacement scenarios on GDP and jobs

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EEI Preliminary Reference Case and Scenario Results

May 21st, 2010

Updated Reference Case

- Nuclear build limits – from NEI
  - Hard-wired units (5,500 MW)
  - Candidate units (4,300 MW) – allowed to be built on or after specified date, but only if deemed economic
  - Economic units – including 8 units above, up to 45 units by 2030 on national basis, regional limits based on existing brownfield sites
- Run year mapping
- Capacity credit update (10%) for wind
- Calibrated coal prices to AEO 2010
  - Minemouth prices calibrated to AEO 2010
  - Transportation prices based on EPA

MODELING ASSUMPTIONS

EEI Master Assumptions Matrix – Reference Case

	EPA ARRA Analysis	EEI Base Case
Electric Demand – National Annual Average	EPA/AEO2009	EPA/AEO2009
Electric Demand - Regional	EPA/AEO2009	EPA/AEO2009
Electric Demand Elasticity	na	na
Natural Gas Supply Curves (Henry Hub)	EPA	EPA
Natural Gas Basis Differentials	EPA	EPA
Coal Price Supply Curves and Coal Transportation Costs	EPA	AEO2010/EPA
Biomass Supply Curves	EPA/AEO2009	EPA/AEO2009
New Build Capital Costs	EPA	EIA AEO/2010
Retrofit Capital Costs	EPA	EVA/NERC
Mercury and HAP Retrofit Structure	EPA	EVA/NERC
Technology Limits	EPA	EPA/NEI
Financing Assumptions – New Builds	EPA	EPA
Financing Assumptions – Retrofits	EPA	EPA for regulated EIA for merchant
3P Policy	CAIR w/ 1.6 million ton bank carryover into 2012	CAIR plus state mercury limits
Carbon	None	None

EEI Reference Case Regulations

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	SO_2 Program	NO_x Program		Mercury Program	CO_2 Program
		Annual	Ozone Season		
CAIR Phase I (2010 -2014)	25 States + DC 2010 retirement ratio: 2:1 Existing Title IV for unaffected states	25 States + DC 1.522 million tons	25 States + DC 0.568 million tons	State Level Regulations CT, CO, DE, GA, IL, MA, MD, ME, MI, MN, MT, NC, NH, NJ,NM, NY, OR, WA, WI	None
CAIR Phase II (2015+)	25 States + DC Retirement ratio: 2.86:1 Existing Title IV for unaffected states	25 States + DC 1.268 million tons	25 States + DC 0.485 million tons		

- BART is included for all BART effected units not included in CAIR for SO_2 and NO_x and WRAP for SO_2.
- WRAP SO_2 is included.
- All existing state regulations for NO_x, SO_2, Hg and CO_2 are included.

EEI Scenario Descriptions

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Scenario	Description
HAPS *(Scenario 1)*	All coal units required to have SCR, scrubber, ACI and fabric filter by 2015
	Ash (2015): All units with wet fly ash disposal and/or wet bottom ash disposal are required to convert to dry handling and install a landfill and wastewater treatment facility. Cost components are as follows: • Conversion to dry fly ash handling - $15 million per unit •Conversion to dry bottom ash handling - $20 million per unit •New Landfill - $30 million per facility •New wastewater treatment facility - $120 million per facility
HAPS+Ash+Water *(Scenario 2)*	Costs applied to units with ponds for fly ash and/or bottom ash based on EIA-923 Schedule 8A, 2008.[1]
	Water (2015): All fossil and nuclear facilities that have at least one once-through cooling unit and would have been classified as a Phase II Facility under the remanded Phase II rule are required to install cooling towers. This does not apply to facilities that are completely closed-cycle cooling even if they use more than 50 million gallons per day. However, it does include some facilities that use helper towers to cool the thermal discharge during portions of the year. The costs are as follows: •Nuclear - $454/gpm (avg. $220/kW) •Fossil - $330/gpm (avg. $215/kW) Costs are applied to units described above based on EPRI's database of electric generating facilities.[2]
HAPS+Ash+Water+CO2 *(Scenario 3)*	CO_2 price consistent with EIA's August 2009 analysis of HR 2454 (Waxman-Markey). Prices start in 2012 at $17/ton and increase to $60/ton in 2030 (2008$).

1 "20100507_Fly Ash and Bottom Ash Summary_Roewer.xls" received on May 7th, 2010
2 "Master List 4-29-10 Working Draft to EEI_calcv1.xls" received on May 5th 2010.

Run Year Structure

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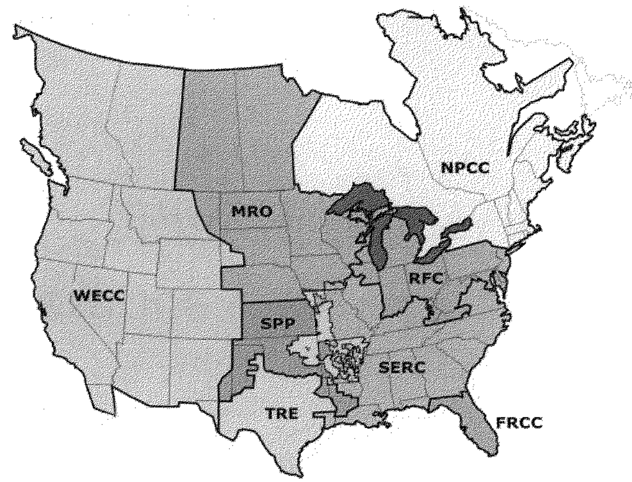
EPA Run Year	EPA Mapped Years
2012	2012-2013
2015	2014-2017
2020	2018-2022
2025	2023-2027
2032	2028-2035

EEI Run Year	EEI Mapped Years
2010	2010
2011	2011
2012	2012
2013	2013
2014	2014
2015	2015
2016	2016
2017	2017
2018	2018
2019	2019
2020	2020-2022
2025	2023-2027
2032	2028-2035

MODELING ASSUMPTIONS

NERC Region Map



FRCC – Florida Reliability Coordinating Council	SERC – SERC Reliability Corporation
MRO – Midwest Reliability Organization	SPP – Southwest Power Pool, RE
NPCC – Northeast Power Coordinating Council	TRE – Texas Regional Entity
RFC – Reliability First Corporation	WECC – Western Electricity Coordinating Council
Note: NERC regional results shown in this presentation include the US only	

Source: http://www.nerc.com

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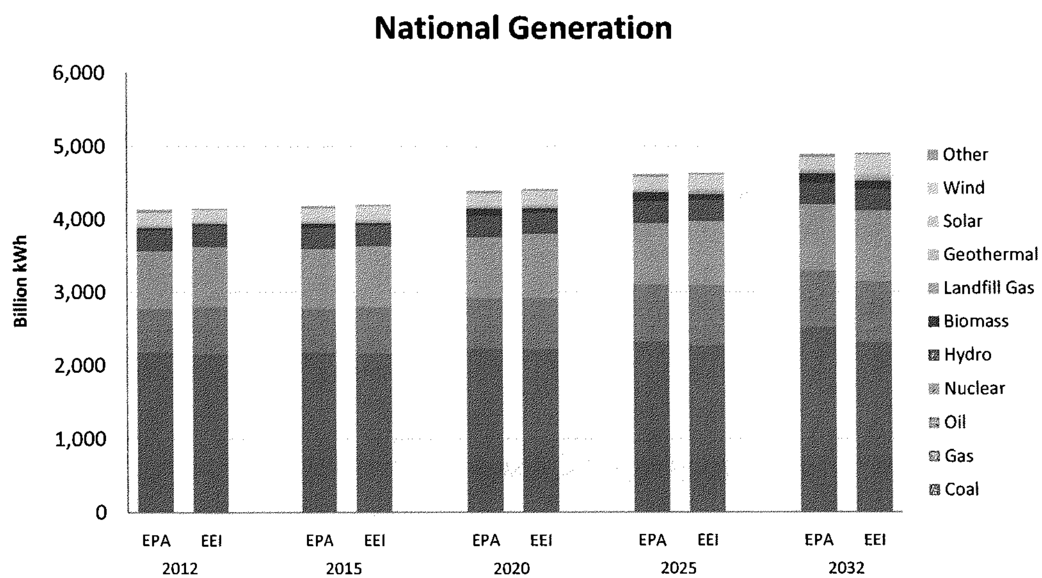
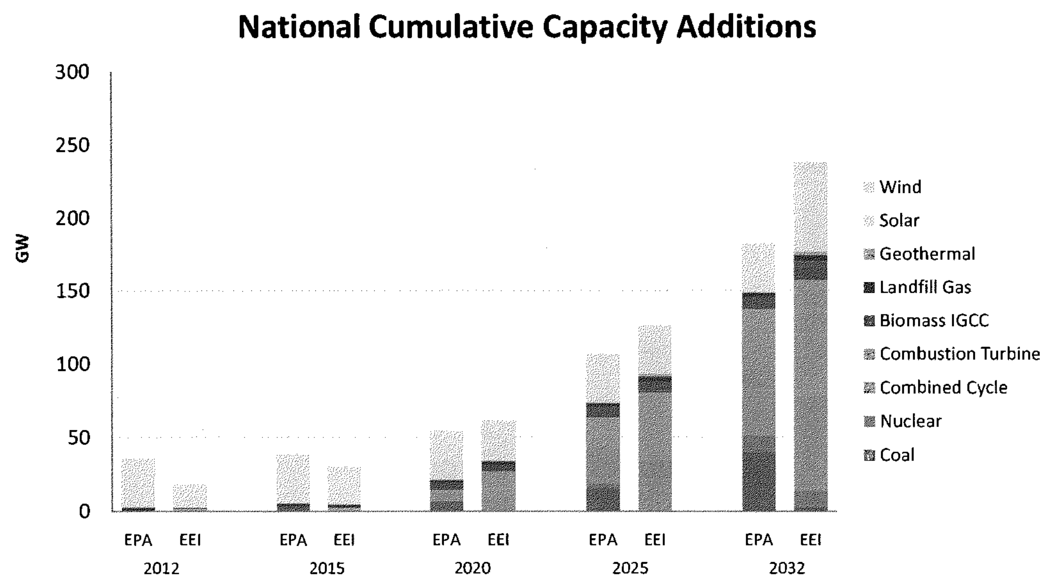
EEI Reference Case - National Level Results Compared to EPA ARRA 2009 Reference Case

National Generation By Type



NATIONAL RESULTS COMPARISON

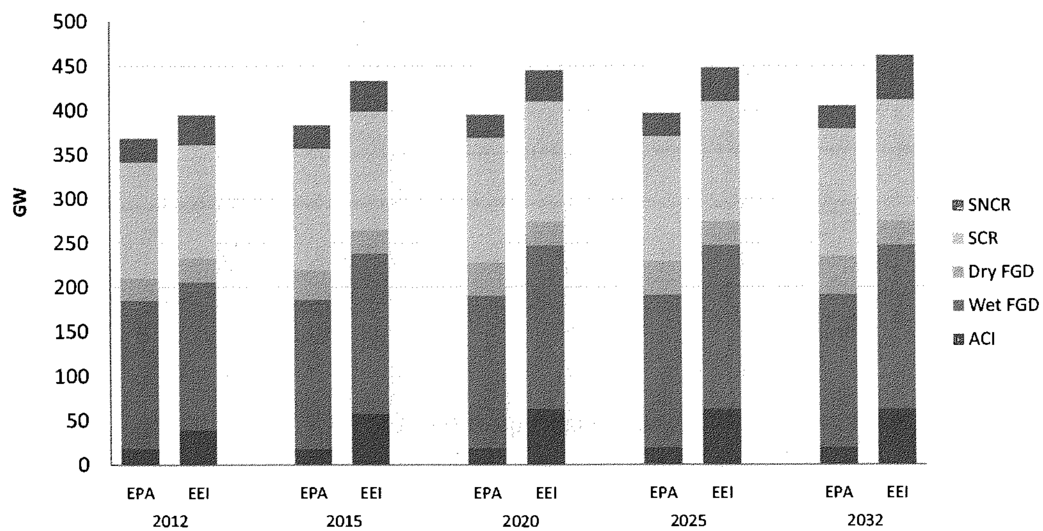
National Cumulative Capacity Additions



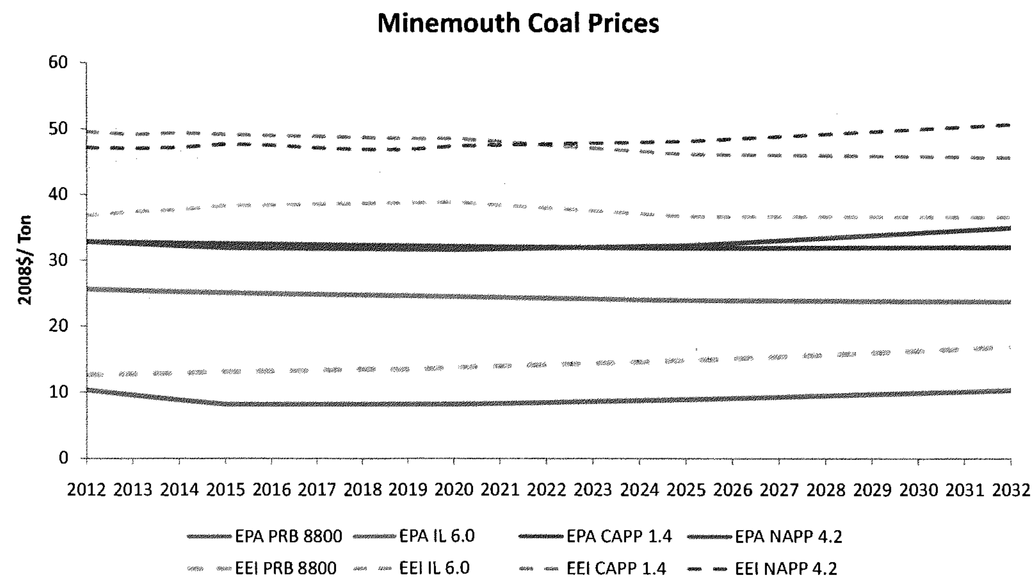
NATIONAL RESULTS COMPARISON

National Cumulative Pollution Control Installations (Existing + Firm + Economic)

National Cumulative Pollution Control Retrofit Installations

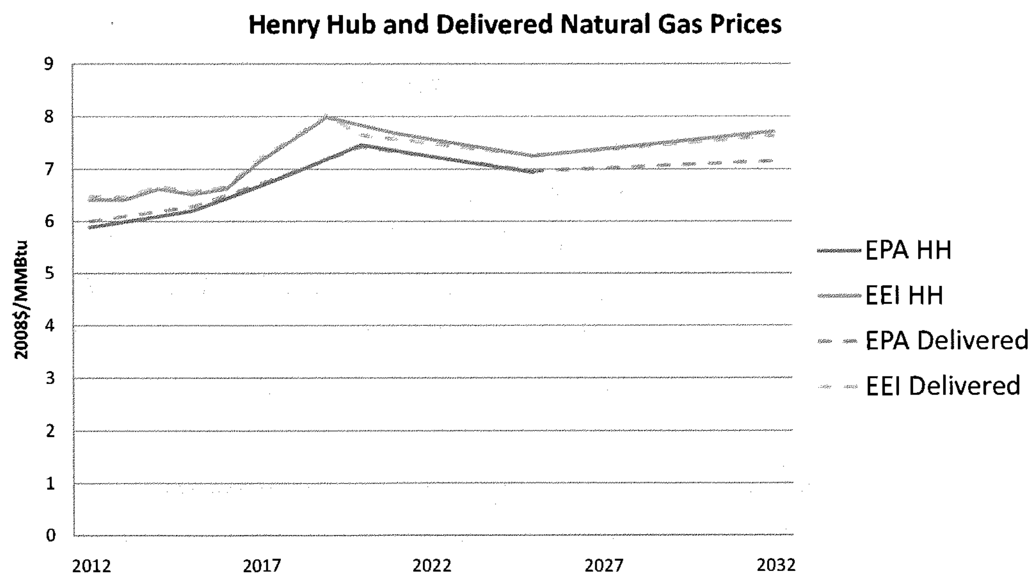


Minemouth Coal Prices



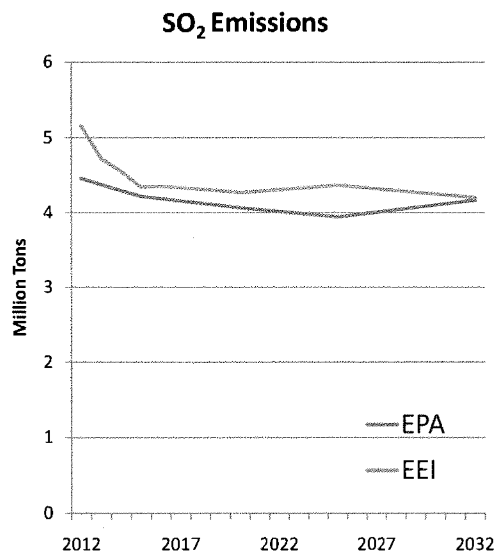
NATIONAL RESULTS COMPARISON

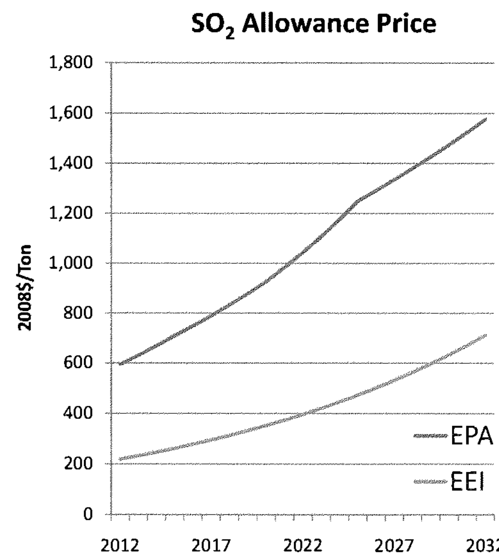
Henry Hub and Delivered Natural Gas Prices



NATIONAL RESULTS COMPARISON

SO_2 Allowance Prices and Emissions

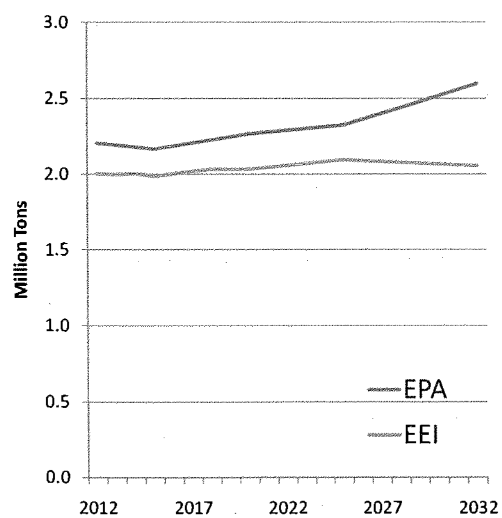




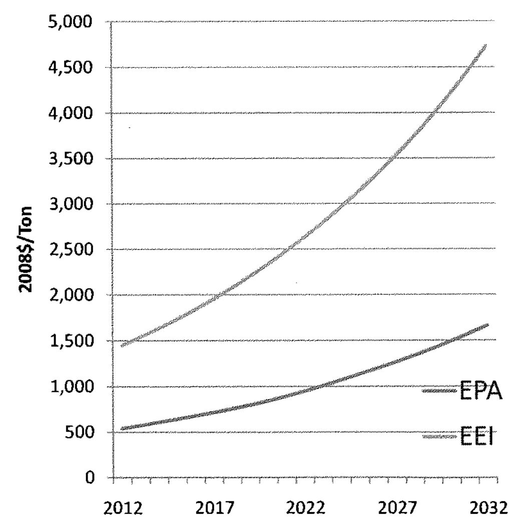
Note: The SO2 price is the $/ton price for units in a CAIR affected state. The $/allowance prices can be derived by dividing by 2 in 2010-2014 and 2.86 in 2015 and beyond.

NO_X Allowance Prices and Emissions

National NO_X Emissions

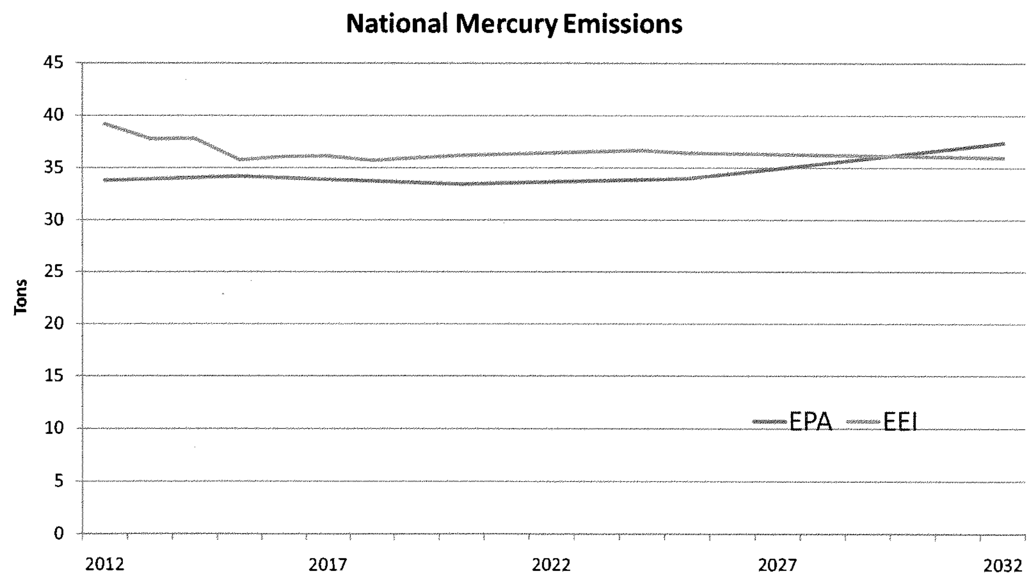


CAIR Annual NO_X Allowance Price



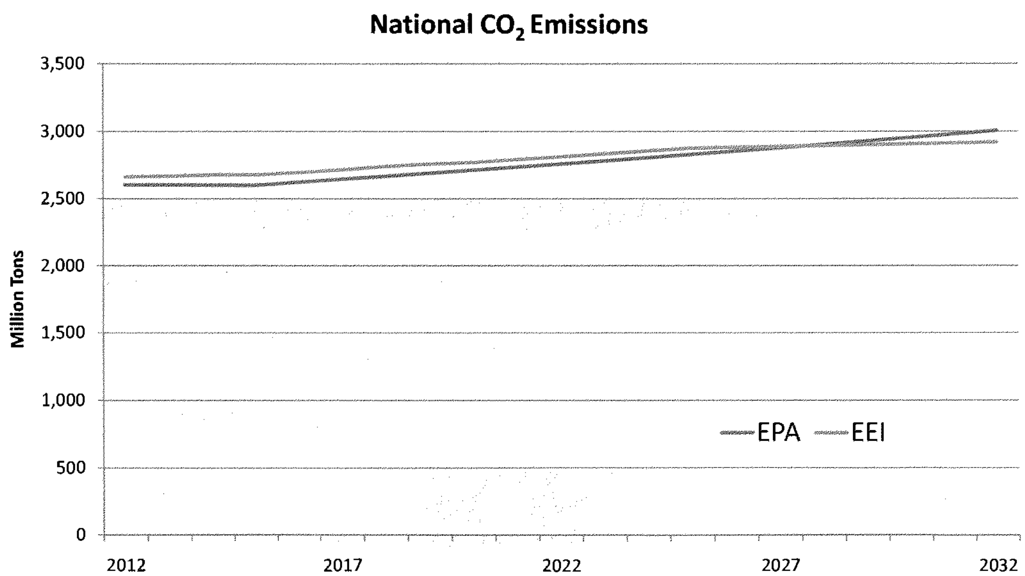
NATIONAL RESULTS COMPARISON

National Mercury Emissions



NATIONAL RESULTS COMPARISON

National CO_2 Emissions



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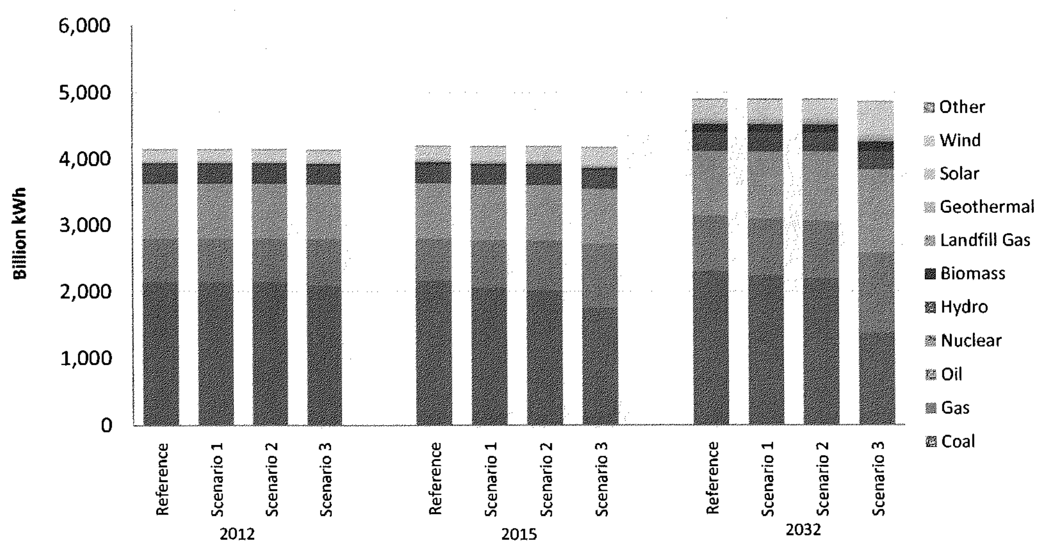
EEI Scenario Results

NATIONAL RESULTS COMPARISON

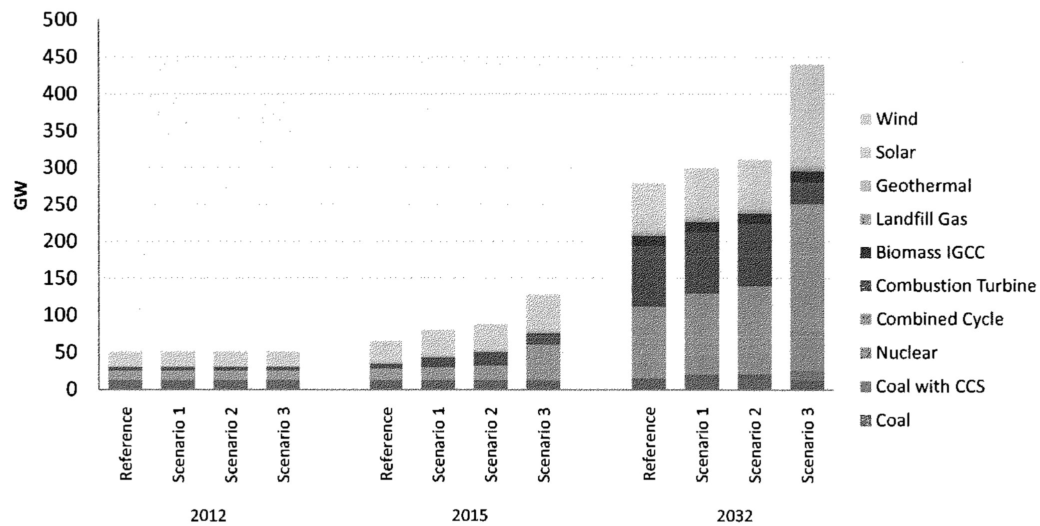
National Generation By Type



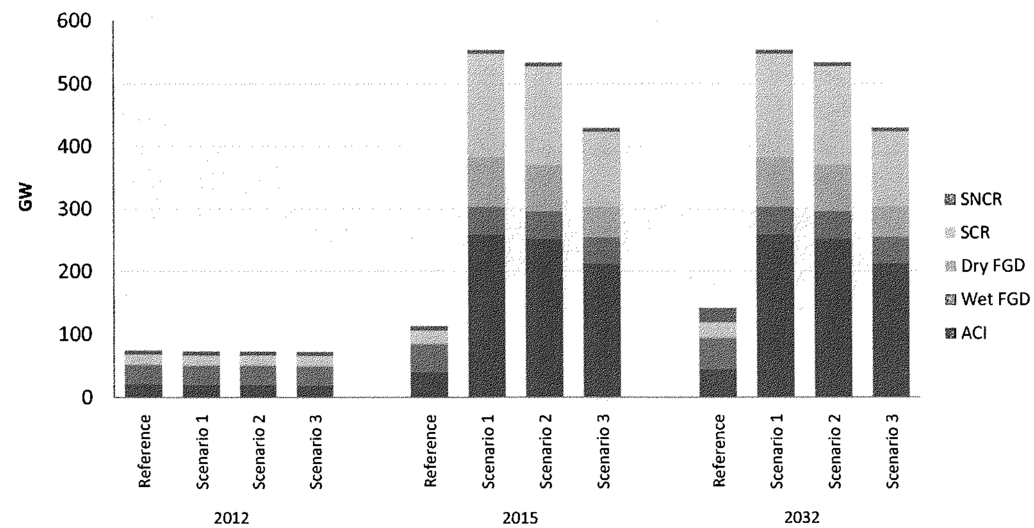
NATIONAL RESULTS COMPARISON

National Cumulative Capacity Additions by Scenario (Firm + Economic)

National Capacity Additions



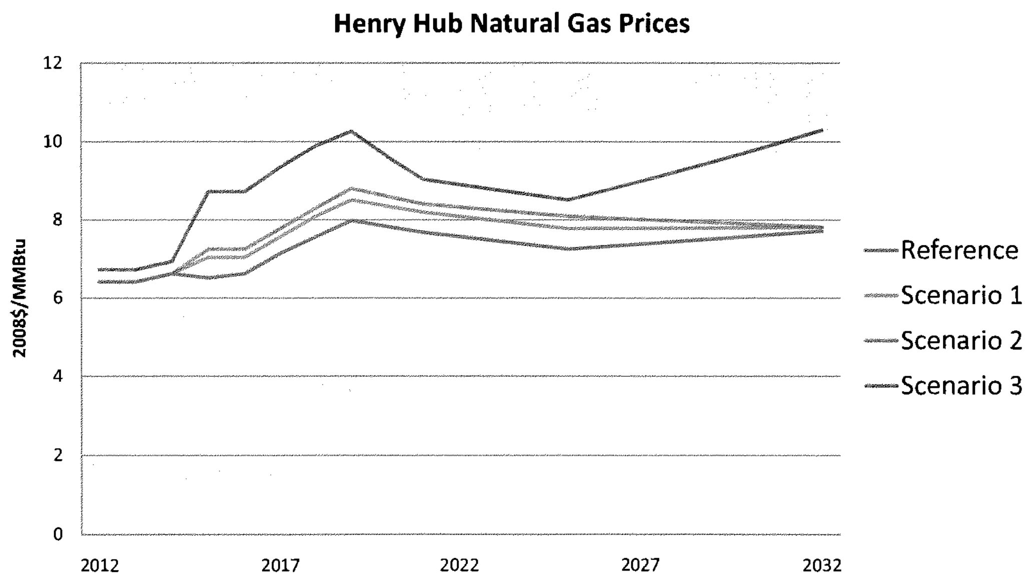
National Cumulative Pollution Control Installations by Scenario (Firm + Economic)



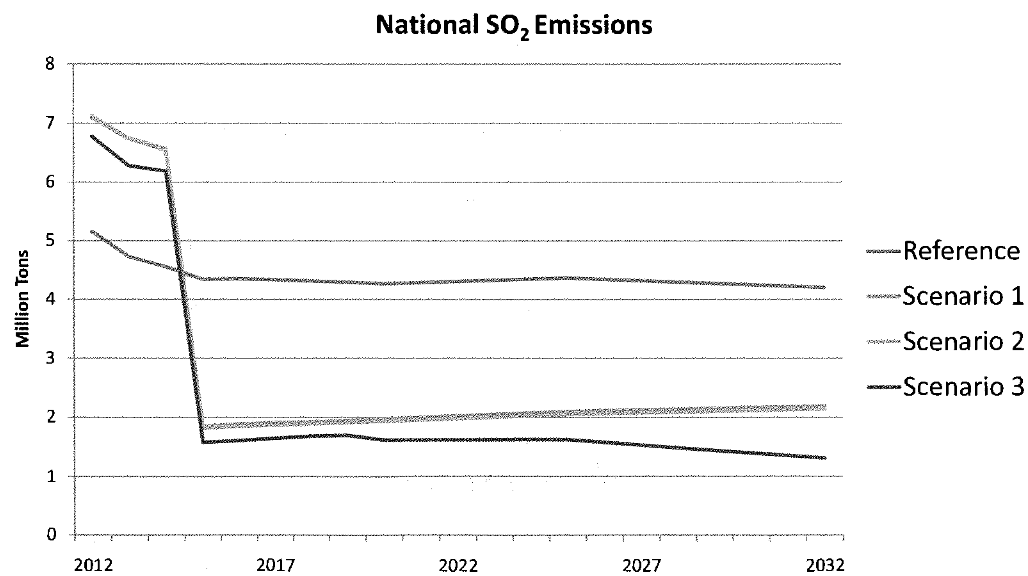
Note: Units may install more than one control and their capacity will be reported separately for each control.

NATIONAL RESULTS COMPARISON

Henry Hub Natural Gas Prices

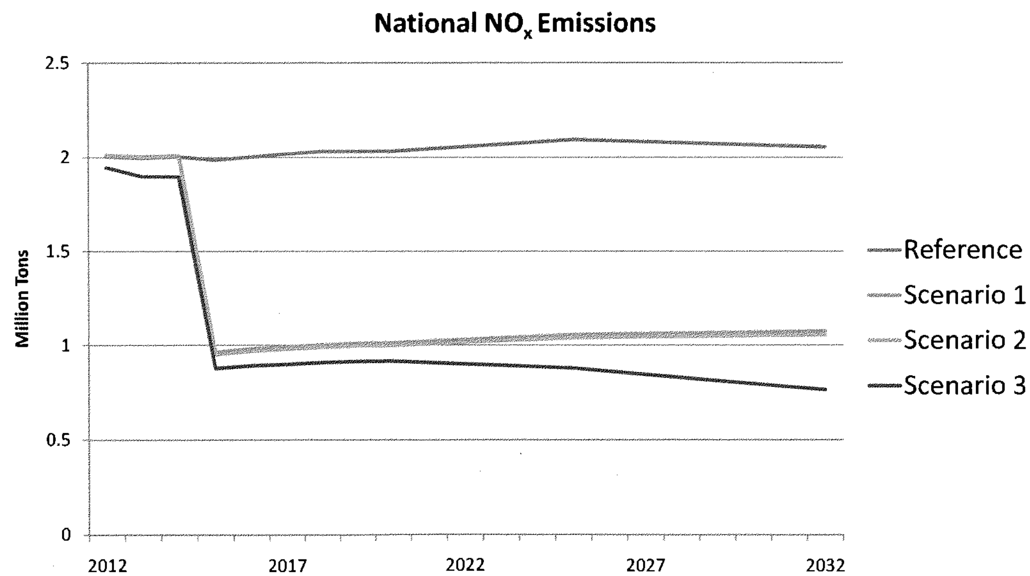


SO_2 Emissions



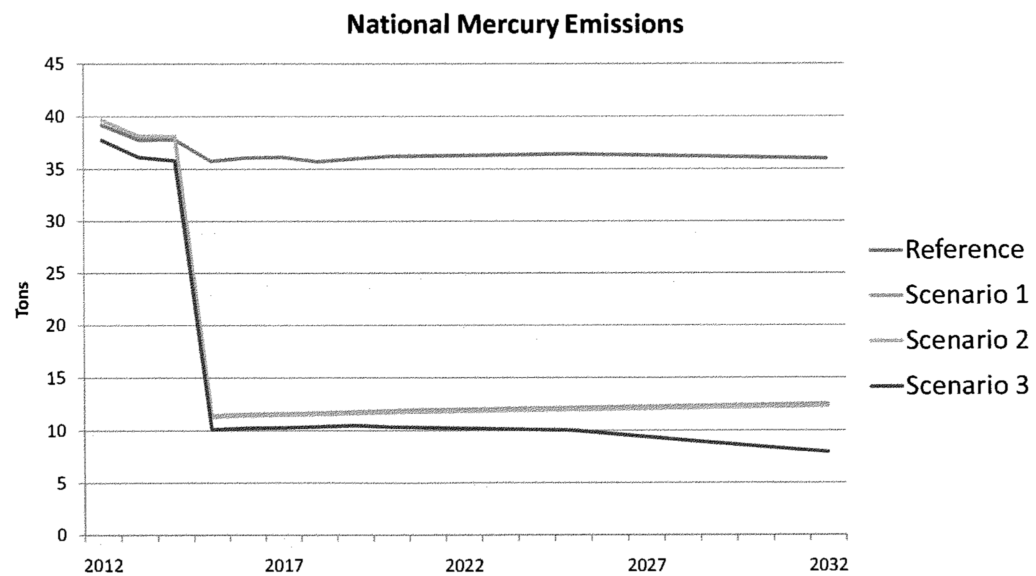
NATIONAL RESULTS COMPARISON

NO_X Emissions



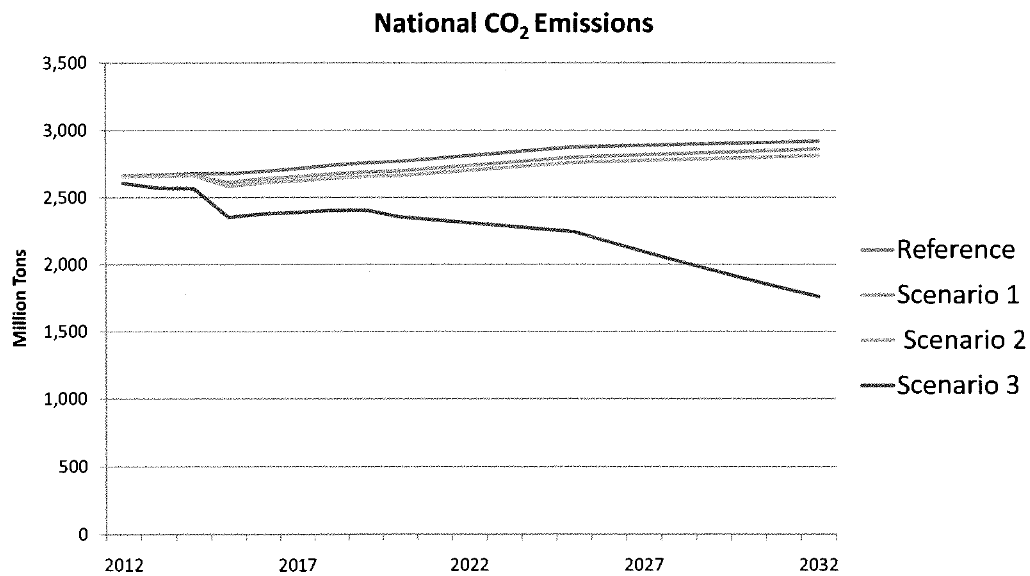
NATIONAL RESULTS COMPARISON

National Mercury Emissions



NATIONAL RESULTS COMPARISON

National CO_2 Emissions



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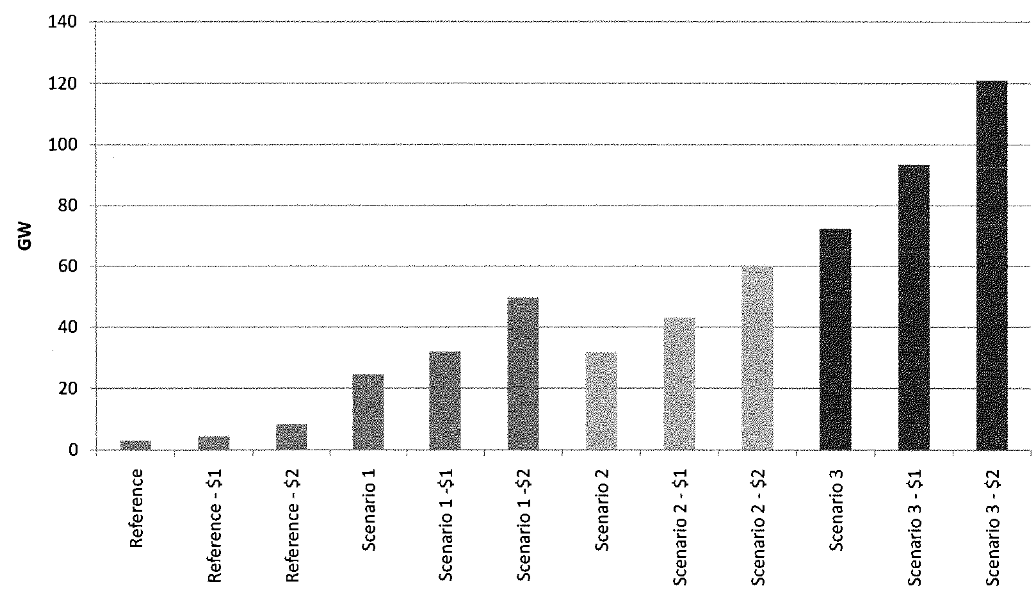
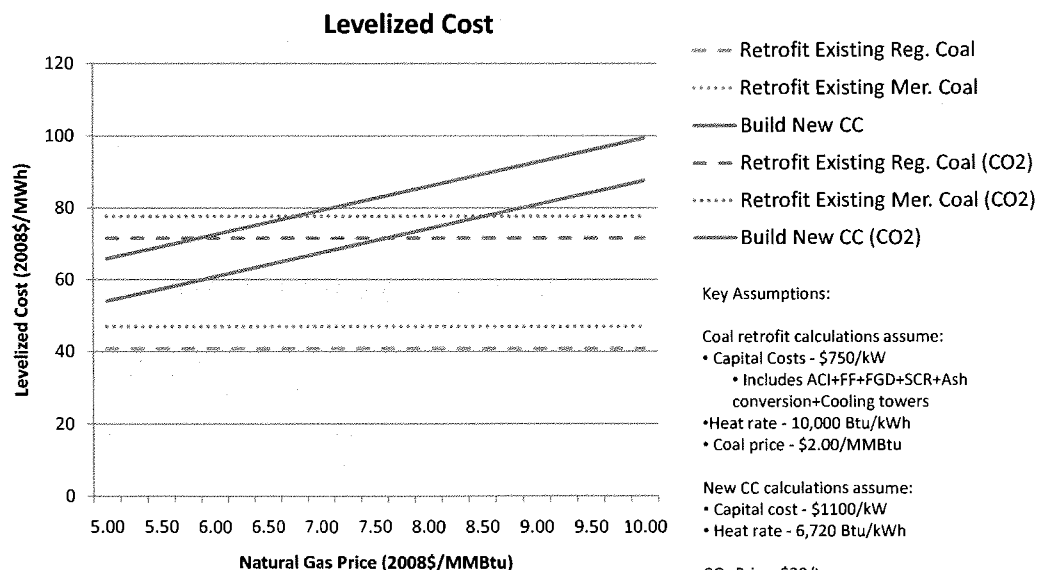
Retirements

RETIREMENTS

Gas Price Sensitivities - Cumulative Coal Retirements through 2015



Natural Gas Prices Impact the Economics of Retrofitting Existing Coal vs. Building New – Avg. Compliance Cost



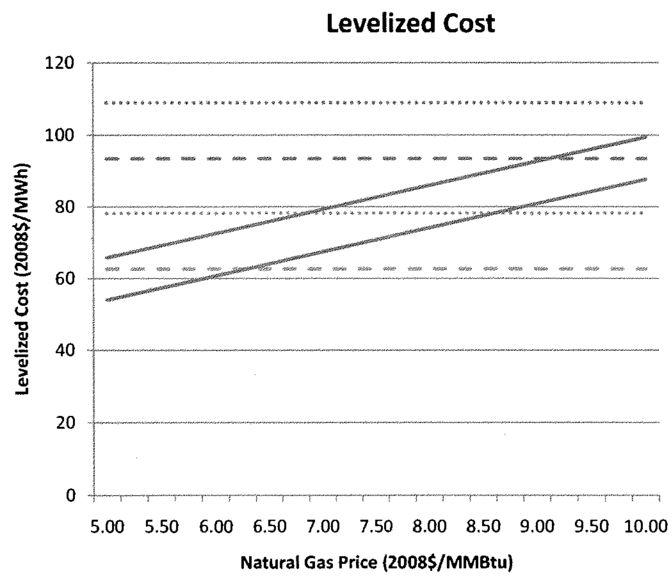
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $750/kW
  - Includes ACI+FF+FGD+SCR+Ash conversion+Cooling towers
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh

CO_2 Price: $30/ton

Natural Gas Prices Impact the Economics of Retrofitting Existing Coal vs. Building New – High Compliance Cost



- Retrofit Existing Reg. Coal
- Retrofit Existing Mer. Coal
- Build New CC
- Retrofit Existing Reg. Coal (CO2)
- Retrofit Existing Mer. Coal (CO2)
- Build New CC (CO2)

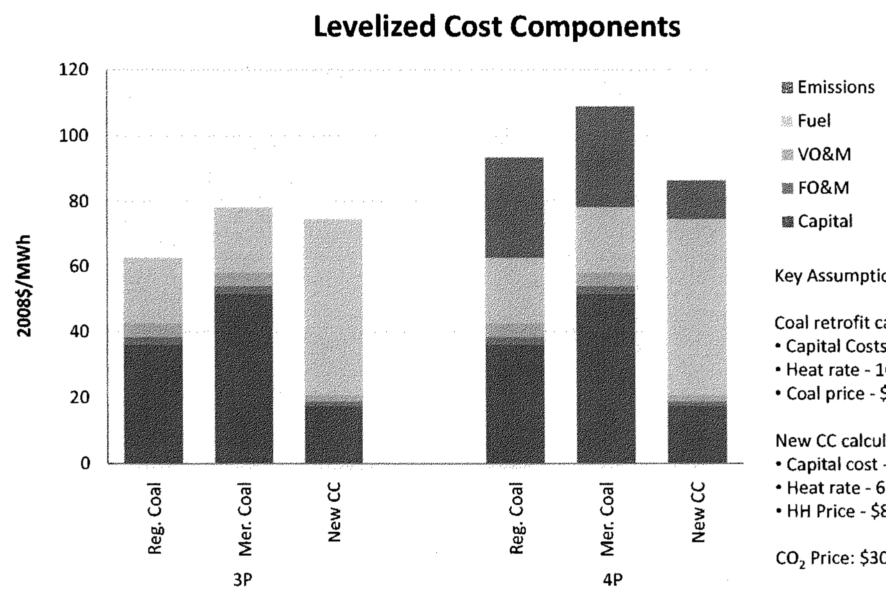
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $1900/kW
  - Includes ACI+FF+FGD+SCR+Ash conversion+Cooling towers
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh

CO_2 Price: $30/ton

Coal vs. CC Levelized Cost Components



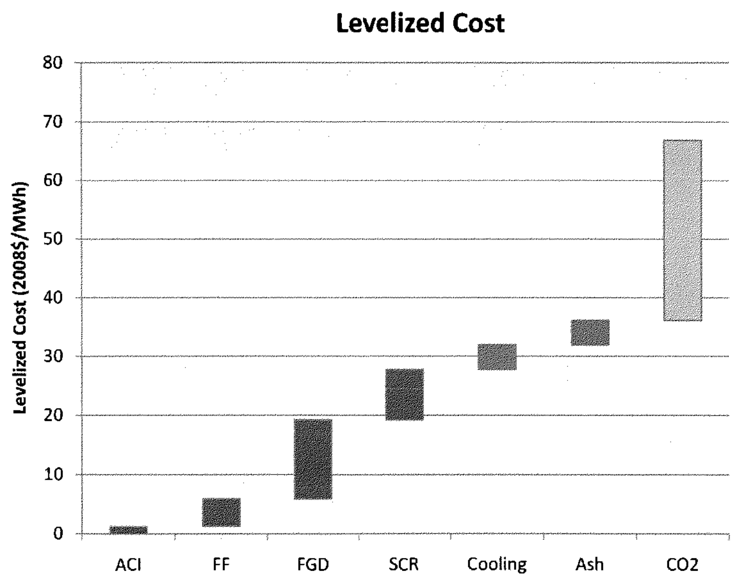
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $1900/kW
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh
- HH Price - $8.00/MMBtu

CO_2 Price: $30/ton

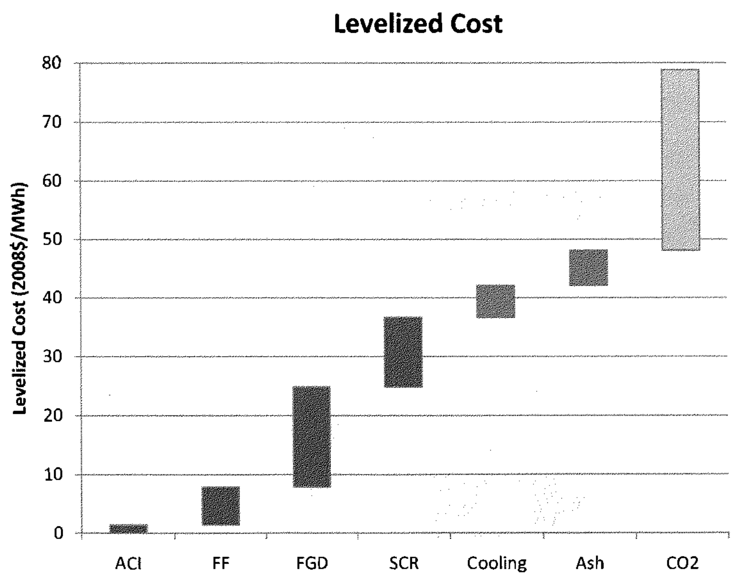
Levelized Regulated Coal Unit Compliance Costs



Key Assumptions:
- Capacity – 500 MW
- Heat Rate – 10,000 Btu/kWh
- CO_2 Price - $30/ton
- Regulated Unit

RETIREMENTS

Levelized Merchant Coal Unit Compliance Costs



Key Assumptions:
- Capacity – 500 MW
- Heat Rate – 10,000 Btu/kWh
- CO_2 Price - $30/ton
- Merchant Unit

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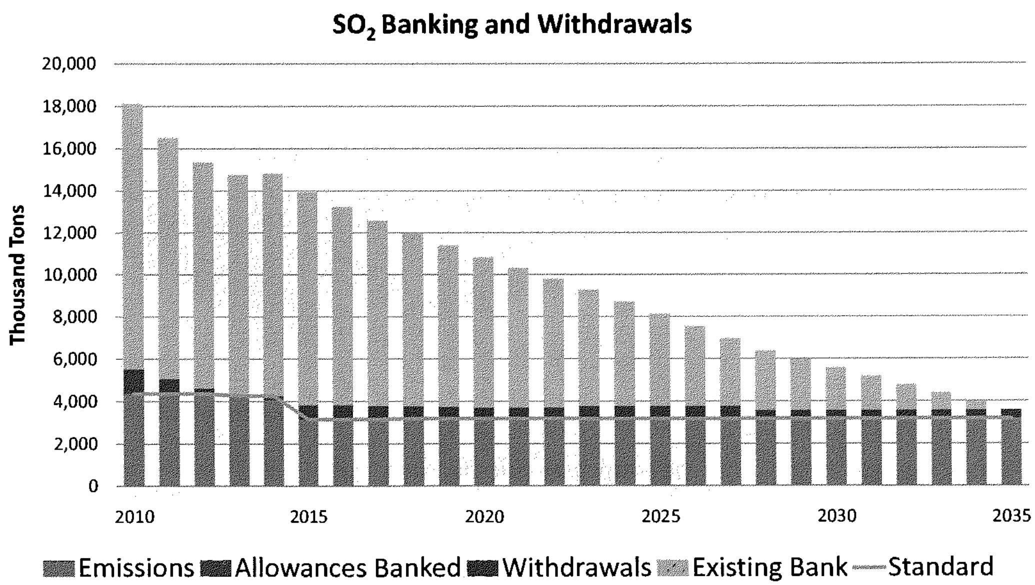
Appendix

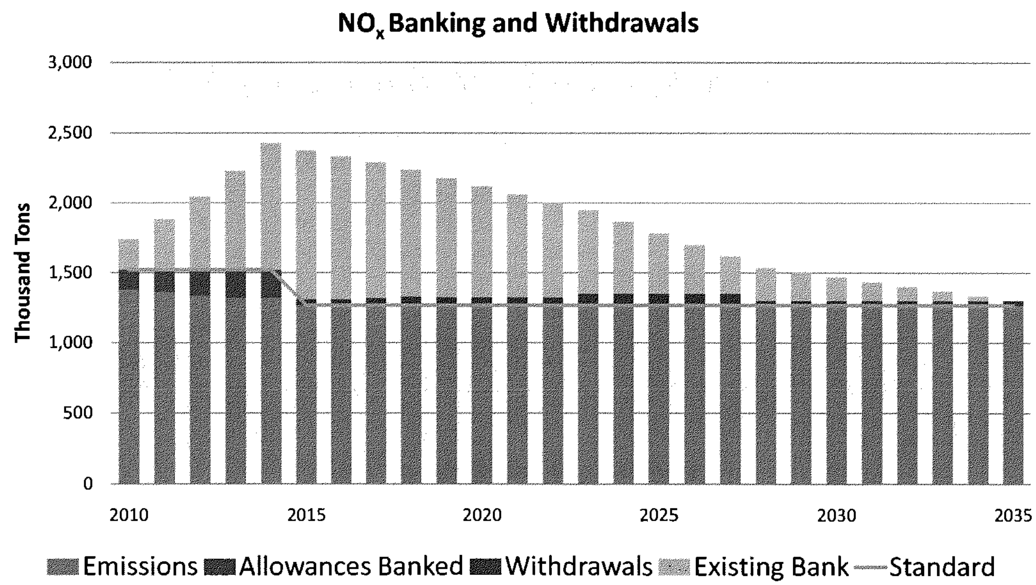
NATIONAL RESULTS COMPARISON

Reference Case SO_2 Banking and Withdrawals



NATIONAL RESULTS COMPARISON

Reference Case NO_x Banking and Withdrawals



WRITTEN STATEMENT OF AMERICAN ELECTRIC POWER

BEFORE THE SENATE ENVIRONMENT AND PUBLIC WORKS' SUBCOMMITTEE ON CLEAN AIR AND NUCLEAR SAFETY: "OVERSIGHT: EPA'S PROPOSAL FOR FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE"

July 22, 2010

American Electric Power (AEP) appreciates the opportunity to submit the following written statement on EPA's proposed Transport Rule to the Senate Environment and Public Works' Subcommittee on Clean Air and Nuclear Safety.

AEP is one of the nation's largest electricity generators -- with nearly 38,000 Megawatts (MW) of generating capacity -- and serves more than five million retail consumers in 11 states in the Midwest and South Central regions of our nation. AEP's generating fleet employs diverse energy sources – including coal, nuclear, hydroelectric, natural gas, oil, and wind power. Most importantly for today's hearing, though, approximately two-thirds of our generating capacity utilizes coal to generate electricity.

AEP's Current Efforts to Achieve Substantial Emissions Reductions

AEP has achieved very substantial SO_2 and NO_x reductions over the last two decades. Our efforts began with an ambitious effort to cut SO_2 and NO_x emissions in the 1990's under the Acid Rain program. The past decade has seen a continuation of this program to transform our fleet of coal-fired generating units. This transformation included the installation of state-of-the-art control technologies at many of our generating stations in order to meet the steep NO_x reduction requirements of the NO_x SIP Call in the early part of the decade. It has continued with a third wave of emissions controls being installed to achieve additional NO_x and SO_2 reductions required under the Clean Air Interstate Rule (CAIR), which EPA is now proposing to replace.

Over the past ten years, AEP has invested over $5 billion in emissions control equipment on our coal units to reduce SO_2 and NO_x emissions and comply with the NO_x SIP Call and CAIR programs and has spent several additional billions of dollars on low sulfur fuel, chemical reagents, and other pollution control O&M costs. As a result of these efforts, over the last 12 years, our annual SO_2 emissions have declined by 775,000 tons (63%) and our annual NO_x emissions have declined by 450,000 tons (79%). These substantial reductions have occurred while AEP has continued to meet increased load demand over the long-term. Most of these reductions have occurred in the Eastern portion of the AEP system. About 80% of AEP coal-fired capacity is located in AEP's eastern footprint, which includes coal-fired plants in Virginia, West Virginia, Ohio, Kentucky, and Indiana. SO_2 and NO_x emissions have been reduced at AEP plants in these states by 64% and 84%, respectively, in the last decade. As a result of all of these pollution control investments, about 2/3 of the AEP Eastern coal-fired fleet is now equipped with the most advanced SO_2 controls – that is, Flue Gas Desulfurization (FGD) which reduces SO_2 emissions by about 95%. Similarly, about 3/4 of the AEP Eastern coal-fired fleet is equipped with the most advanced NOx controls, that is, Selective Catalytic Reduction (SCR) which reduces NOx emissions by about 90%. All of these units are located in States that would be required to make additional immediate reductions under EPA's Proposed Transport Rule.

We expect this transformation of our coal fleet to continue in the coming decade. In addition to EPA's Proposed Transport Rule, we currently have requirements to reduce SO_2 and NO_x emissions further at units that are regulated under the Clean Air Visibility Rule. We are also moving forward with emissions reduction projects to meet our obligations under the consent decree that AEP entered into with EPA and other litigants related to the New Source Review provisions of the Clean Air Act. While considerable uncertainty exists over the timing and form of other future regulations, we know that EPA is actively pursuing additional programs to reduce emissions, including a new rule to address mercury and other hazardous air pollutants, and the establishment of more stringent national ambient air quality standards. Although we are committed to working with EPA in the development of future control requirements, we have concerns about the time frame for compliance with these multiple and overlapping programs, as well as the stringency and structure of the underlying regulatory requirements. Some of those concerns are:

- The cumulative costs of multiple requirements and their impacts on our customers;

- Immediate deadlines that do not take into account the need for economic recovery in our service territories;

- The risk of stranded investments that may result from installation of expensive pollution control equipment in order to meet near-term environmental regulations which are effectively overridden by future EPA standards;

- Lack of coordination of the control requirements imposed under future regulatory programs;

- Potential adverse impacts on grid reliability due to wide-scale unit outages required to install emission controls as well as a large number of unit retirements within a short compliance time frame;

- The significant new investments that may be required by non-air environmental programs including EPA's recently proposed rule for disposal of coal combustion by products, EPA's revisions to cooling water intake rules, and its initiative to update its steam-electric effluent guidelines; and

- The potential investments required to meet new EPA greenhouse gas regulations and/or new federal climate legislation should it pass Congress.

This cumulative cost exposure is raising significant concerns about the economic viability of a large number of existing coal-fired units, as well as potential impacts to grid reliability and imposition of substantial increases in retail electricity prices on consumers. No evaluation of these potential cumulative impacts has been undertaken. Instead, EPA has engaged in only piecemeal examination of individual rules, and ignored the sustained economic pressures created by these increasingly stringent requirements.

Taking all of these issues into consideration, the transformation that we see in the coming decade could be very different from the last. This past decade saw the installation of emissions controls on many units on the AEP fleet as well as across the country. Those installations preserved the value of capital already invested, created new jobs, and produced significant environmental benefits. As the first phase of CAIR went into effect during 2009 and 2010, amid some of the most difficult economic times our country has faced, our customers have shouldered the cost increases associated with these significant investments. The recovery in the Midwest and South Central regions has not yet begun, and the prospects for recovery would be impaired by additional EPA regulations that do not carefully balance the twin goals of environmental and economic progress.

This coming decade may see more decisions to retire some units in addition to adding controls on other units. In fact, some companies have already made announcements about plans to retire older, smaller coal-fired units in the face of ever-increasing environmental obligations. These retirements often eliminate the best-paying jobs in relatively rural regions where there is little prospect for the replacement of those jobs, and threaten state and local governmental budgets that rely on tax revenues from these facilities and their employees. But the impacts go well beyond these local concerns. These retirements also can have significant impacts on the reliability of the electric grid. The key to our ability to manage effectively this significant transition will be the timing and achievability of the compliance obligations and the flexibility for complying with the control requirements of the programs. New Clean Air Act rules that achieve environmental objectives with reasonable schedules and compliance flexibility could be extremely helpful to protecting the environment without unduly hurting American workers and delaying our economic recovery.

The Proposed Transport Rule

Unfortunately, EPA's Transport Rule as currently proposed does not appropriately balance environmental and economic objectives. While we commend EPA for retaining some of the flexibility of intrastate and regional emissions trading of SO_2 and NO_x, the timing of the reduction requirements, the relative inflexibility of other provisions of the rule, and the stringency of the emission reductions, particularly as it applies to SO_2, would very substantially increase the cost of compliance and could likely have significant adverse impacts on reliability and the regional economy. AEP is particularly concerned about the following provisions:

SO_2 and NO_x Requirements in 2012 are Too Soon and Infeasible

One of our greatest concerns with EPA's proposed Transport Rule is that the schedule for implementing the new program's more stringent emission caps is too fast. Under the proposal, the Phase I caps apply at the beginning of 2012 and the even more stringent Phase II caps apply at the beginning of 2014.

Assuming the proposed rule goes final a little less than a year from now (i.e. EPA's current schedule is Spring of 2011), Phase I of the program would allow **only** a little more than **6 months** in total to implement the new emission budgets, establish emission trading programs **and** for companies to make the needed investments to comply with these new limits.

Six months, let alone a year or two, is not nearly enough time for this. Having brand new emission caps, state budgets and allowance allocations in 2012 creates major logistical challenges for the electric power sector and for the states that must implement the programs. Companies will not have sufficient time to design, permit, fabricate, and install emissions controls that may be necessary for meeting the new reduction requirements. Moreover, additional time is necessary to coordinate installation of major pollution control equipment during spring and fall outage schedules to ensure reliability of the entire utility system. While the EPA claims that the Phase I will require little investment in the way of new controls, its assumption is predicated upon high level modeling and not the actual physical, contractual and financial constraints at these facilities during such a short time frame. This very short time frame is made worse by the constraints placed on emissions trading – assuming that this option is even adopted for implementing the reduction requirements. Notably, the constraints on trading will effectively limit a company's ability to achieve compliance in the least cost manner, and hence drive up the compliance cost of the program.

Simply put, EPA needs to provide more time for the full implementation of the new Transport Rule. At the very least, EPA should keep in place for at least several more years the existing CAIR program. The SO_2 and NO_x reduction levels of the CAIR program were set at levels that EPA determined were appropriate to remedy interstate transport problems for both the ozone and fine particulate matter standards. Under this approach, Phase I of the Transport Rule would not begin until 2014 or 2015. This extra time would provide additional time for companies to install the new control equipment to meet additional reduction requirements of the Transport Rule and for States to adopt and begin to implement this new control program.

Furthermore, the proposed timeline for implementation is inconsistent with past multi-pollutant reduction programs. Congress, for example, provided almost a decade to implement in two phases the SO_2 and NO_x reductions mandated under the Acid Rain program. Similarly, EPA established a two-phase program for achieving the reduction obligations under the CAIR program. The Phase I deadlines for CAIR allowed almost five years from promulgation of the final rule until the first compliance year for SO_2 and almost four years for NO_x. Similarly, EPA adopted the NO_x SIP-Call program in September 1998, allowed States a full year until September 1999 to submit implementation plans, and did not apply the NO_x control requirements until May 2003, over 4 ½ years after EPA promulgation of the final rule.

Timing of Phase II SO_2 Caps is also Too Soon and the Caps are Very Stringent

The SO_2 caps in 2014 are significantly more stringent than those in 2012 for about half of the States covered under Transport Rule.[1] These States are ones most reliant on coal and face the major portion of the compliance burden for limiting SO_2 emissions. A 2014 deadline for a second phase of SO_2 reductions further complicates the planning and logistical challenges for compliance. In particular, the SO_2 budget limits in Eastern states which have AEP coal-fired power plants (*i.e.*, Virginia, West Virginia, Ohio, Kentucky and Indiana) are very stringent. The tonnage SO_2 limits in these states amount to an average rate of approximately 0.20 to 0.30 lbs SO_2 per million Btu, which can only be just attained by a scrubbed power plant using higher sulfur coal removing about 95% of the SO_2 from the flue gas. (Note: 95% is the current maximum level of removal that most retrofit scrubber designs for existing units can reliably and consistently achieve on an annual basis). As such, these limits would require most of AEP's coal-fired power plant units in these states to either to install FGD, switch to natural gas or retire early in order to comply.

Retrofitting additional scrubbers throughout the Phase II states by the beginning of 2014 is infeasible given that the typical time frame to design, permit, fabricate, and install such major pollution control equipment in our experience has taken more than three years. Even a three-plus-year time frame may be optimistic, given that most other utilities in the East will also be effectively required to install scrubbers over the exact same time frame. A number of different utilities installing scrubbers at many different units over the exact same time frame could severely constrain supplies of materials, skilled labor and engineering talent, thereby driving up costs and lengthening the timeline for project completion. Further, most of the coal capacity retrofitted will be older, smaller coal units. Older and smaller capacity units often have space and design constraints and thus typically have a much greater retrofit difficulty given that they were not designed originally for back-end pollution controls. Finally, there are many other logistical challenges that AEP and other companies would need to address. Notable examples include scheduling outages for making final scrubber connections to the

[1] Specifically, 13 States, out of the 28 States covered under the proposed Transport Rule, would be subject to more stringent SO_2 reduction requirements in Phase II that starts in 2014.

generating unit,[2] as well as getting landfill, waste water and other permits related to the handling and disposal of scrubber waste generated by the new scrubber. In addition to the short time frame, obtaining these new permits is complicated by the pending EPA initiatives to regulate coal combustion residues and update its steam-electric effluent guidelines.

Given that these rules were only proposed a few weeks ago and are very detailed and extensive, AEP has not yet had a chance to do a detailed analysis of our likely compliance options and choices to meet the budget targets. However, our initial analysis suggests that the proposed Transport Rule, combined with all of the other EPA rules for regulating coal combustion residuals, mercury, other hazardous air pollutants, and CO_2, would likely make additional retrofit pollution controls such as scrubbers and SCR on older and smaller units uneconomic, even if they could be installed on time. In our case, 4000 to 6000 MW, or about 20-30% of our coal fired capacity in the Eastern states we serve could be retired instead of retrofitted by the 2014-15 time frame under all of these emerging rules.

There is no question that additional, costly control technology will be needed on many units across many utilities in the East and that our experience is not atypical. Similarly for other companies, the EPA rules may lead to decisions to shut down units prematurely or replace existing coal-fired generation with natural gas instead of incurring the cost of controls. Looking at this for the country's coal fleet, the combination of taking units out of service to install controls and retiring a significant number of units instead of installing controls presents a potential reliability concern of major significance for some regions of the country.

The Transport Rule Drastically Limits the Use of Banked Allowances, Resulting in Higher Than Necessary Costs

[2] Furthermore, additional time is necessary given that installation will need to be undertaken during spring or fall outage schedules, when electricity demand is not at peak levels.

In the interim CAIR program, EPA currently allows power plants to reduce SO_2 and NO_x emissions more than required in a given year and save or "bank" these emission allowances for use in a later compliance year. Emissions banking allows companies to comply at a lower overall cost because very high cost reductions and expensive pollution control equipment can be delayed until the most optimal time frame by utilizing banked allowances. More importantly, banking provides a net environmental benefit, because more emission reductions and hence environmental improvement occurs sooner.

Under the proposed Transport Rule, EPA has eliminated the use of previously banked SO_2 allowances after the end of 2011. As a consequence, the market price of SO_2 allowances has dropped to nearly zero and the SO_2 market has been effectively eviscerated. In effect, electric companies and their ratepayers and various market participants who have funded extra emission reductions and environmental improvement through advanced pollution control investments over the past several years have been penalized billions of dollars.

To minimize these adverse impacts, EPA should extend the current CAIR rule for several more years before beginning Phase I of the Transport Rule and allow for banked allowances to be used during this time period. The use of banked allowances could help smooth the transition to the tighter emission caps under the new Transport Rule, substantially reduce the costs of compliance, and help ameliorate retirement and reliability concerns. Also, the continuation of the CAIR program will ensure progress to attaining the air quality goals under the Clean Air Act. This is confirmed by the fact that the SO_2 and NO_x reduction levels of the CAIR program were set at levels that EPA determined were appropriate to remedy interstate transport problems for both the ozone and fine particulate matter standards.

The Transport Rule Provides No Certainty Regarding Future Reduction Requirements for SO_2 and NO_x Under Later EPA Rules

EPA has noted in the proposed rule that it plans to further revise the rule and tighten the utility SO_2 and NO_x emissions caps in future rulemakings in order to meet its new fine particle and new ozone standards.[3] Without knowing what levels of reductions will ultimately be required and by when, the investment planning process for the current proposed Transport Rule is completely untenable. The risk of stranded or unnecessary pollution control costs increases dramatically. Such uncertainty also increases the probability that coal power plant units will be prematurely retired in order to avoid these investment and rate recovery risks.

EPA's Economic Analysis is Flawed and Deficient in Justifying the New Transport Rule

As a general matter, EPA's analysis fails to account for the impact of multiple uncoordinated rules and policies on the investment decisions being made at coal-fired power plants. As noted earlier in this statement, in addition to the proposed Transport Rule, coal-fired power plants face a yet to be determined set of additional SO_2 and NO_x reductions to meet new ozone and fine particulate standards, future mercury and hazardous air pollutant rules, recently proposed ash disposal rules, possible water rules and of course the prospects of the regulation of greenhouse gases under either existing Clean Air Act authorities or federal climate change legislation.

The impact of investments and additional operating costs that are needed to comply with all of these EPA rules and regulations in addition to the proposed Transport Rule is substantial and should be factored in, specifically when considering the retrofit pollution control versus retirement or conversion to gas decision. It is evident that EPA did not do this. In fact, EPA only predicts an additional 1.2 Gigawatts of retirements across the United States due to this rule. AEP alone projects it will have more retirements than EPA's projection for the U.S. in the 2014-2015 time frame.

In addition, while we have only just begun to assess EPA's detailed supporting analyses for the proposed Transport Rule given its length and complexity, our initial review with

[3] *See* Proposed Transport Rule at pages 90-92.

regard to AEP assumed pollution control costs and unit information points to several significant errors, which will affect the accuracy of the state and individual plant level cost-effectiveness analysis and assumed emission budget findings:

- EPA assumes FGD, SCR and other pollution control costs that are substantially lower than AEP and industry's ACTUAL experience. For example, EPA assumes that an FGD on a 700 MW unit would cost ~$240/kW ($2008). However, recent bids and quotes received by AEP for new FGD installations suggests that the actual costs are likely to be more double the EPA assumption. Likewise, the SCR costs assumed by EPA are also lower than recent experience would suggest. These faulty assumptions drastically understate the costs and cost per ton of achieving the reductions and incorrectly skew EPA's analysis towards retrofit decisions instead of retirement decisions.

- Similarly, EPA uses an inappropriately low financial capital charge rate based on an unrealistic 30-year remaining book life for older coal units. For most of the older coal fired units that AEP will be considering whether to retrofit, repower or retire the remaining lifetime is much shorter - generally 10-15 years or less. As a result, EPA dramatically understates the annual capital charges of investments in these plants and the cost effectiveness of these emission reductions. This unrealistically skews the analysis towards retrofits instead of retirements and understates the overall costs of the proposed Transport Rule.

- EPA assumed that AEP will have scrubbed its 585 MW Muskingum River Unit No. 5 in Ohio by January 1, 2011 or only 6 months from now. However, while preliminary engineering was begun several years ago, there is no ongoing construction activity associated with this retrofit project. Even if engineering and construction recommenced today, the actual in-service date for the scrubber would still be at least three years from now. As such, the EPA assumption that this unit would be scrubbed by 2011 is completely infeasible and inaccurate.

- EPA assumes that FGD retrofits at the Kyger Creek (1,085 MW) and Clifty Creek (1,302 MW) Plants are currently online. However, the retrofit projects underway at these plants are not in service, are currently suspended and considerable financial investment and time will be needed to complete these projects.

- EPA assumes that the AEP Muskingum 1-4 units (830 MW) are able shift to lower sulfur coals in its analysis (1.0-1.4 lb-SO_2/MMBtu). However, these units are wet bottom / cyclone-fired boilers, which cannot tolerate most low-sulfur Eastern coals due to their high ash fusion temperatures. Thus, this is a very unrealistic assumption.

Note: Similar to other utility companies, AEP is only beginning its review of the economic analysis and will no doubt have additional comments and corrections that it will be submitting to EPA at the end of the comment period.

Multi-Pollutant Legislation

The combination of EPA's proposed transport rule and multiple other new air pollution regulations will likely result in a series of relatively inflexible and stringent air pollution regulations with inadequate timelines and high costs. As already noted, in addition to high costs borne by our electricity customers, these rules could also result in many premature plant retirements. This is turn would mean an attendant loss of skilled local jobs in some of the poorest rural counties in industrial states that are still reeling from the effects of the recession.

We believe however there is a sound remedy for this patchwork quilt of uncoordinated environmental regulations, which is for Congress to pass environmentally sound, flexible and cost effective multi-pollutant legislation. Senator Carper has provided leadership by introducing on February 4, 2010 the "Clean Air Act Amendments of 2010" (S. 2995) and John McManus of AEP provided our comments on this bill through testimony in March of this year. As indicated in this testimony, AEP does not support the Clean Air Act Amendments of 2010 as currently drafted, though we will reevaluate the bill after it is amended. In particular, based on our concerns with the current bill that we identified in March, we recommend the following revisions to the bill:

- **Timing--** The bill's emission limits require ambitious SO_2 and NO_x reductions that are phased in too rapidly. Longer time frames would enable better planning and avoid premature plant shutdowns or excessively high costs for pollution controls due to supply constraints. We recommend that the first phase of the SO_2 and NO_x program begin in 2015 (instead of 2012) with the other phases also extended by three years to allow for a reasonable amount of time for compliance. Similarly, we recommend that at least five years be provided to comply with the mercury MACT provisions under the Act.

- **Safe Harbor from Additional Control Requirements--** In exchange for establishing clear, environmentally ambitious and sound emission targets, S.2995 needs to ensure that no additional SO_2 and NO_x reduction requirements are imposed by EPA through transport rules or section 126 petitions. Otherwise, the key attributes of multi-pollutant legislation - providing greater flexibility, compliance certainty and lower costs - are lost. By the time the bill's SO_2 and NO_x emissions caps are fully implemented, it is reasonable to assume that almost all existing coal-fired generating units will be either retrofitted with the full suite of control technologies including scrubbers and SCR or retired. The bill should provide some certainty that no further requirements will apply for these pollutants. The contribution of this emission source sector to attaining the air quality goals for ozone and $PM_{2.5}$, and reasonable progress toward national visibility goals will have been more than adequately addressed.

- **Coordination of Non-Mercury HAP Control Requirements--** A related issue is the regulation of non-mercury hazardous air pollutants (HAPs) emitted from power plants. The Carper bill, as drafted, does nothing to coordinate the reduction of these non-mercury HAPs with the stringent SO_2 and NO_x reduction requirements imposed on power plants under the bill. AEP believes this failure will unnecessarily increase control costs by substantial amounts and force

- **Greater Flexibility with Regard to Achieving Mercury Requirements--** The bill's goal of achieving a 90% reduction in mercury emissions from coal-fired power plants as a whole through source-specific performance standards may not be technically feasible at all coal-fired power plants. Moreover, the imposition of stringent mercury performance standards that would result from a 90% mercury emissions reduction – even if it were technically feasible – is likely to impose excessively high control costs to meet the mercury emissions standards at many coal-fired units. AEP believes that this approach is a recipe for increasing costs of electricity and forcing premature retirements. One possible solution to this problem – without compromising on the environmental goal of achieving a 90% reduction – is to provide greater flexibility in meeting the mercury performance standards. This can be achieved by adding provisions to the bill that would authorize emissions averaging over a broader geographic area (*e.g.*, across a state or specified geographic radius) and alternative emission limits in the event the installation of cost-effective mercury control technology does not achieve the applicable mercury performance standard. AEP urges the consideration of these flexibility mechanisms as an effective way to reduce greatly the costs while maintaining the environmental integrity of the program.

- **Fix Emission Allowance Allocations and Auctioning--** Auctioning of emission allowances simply increases overall costs to utilities and their customers with no attendant environmental benefits. We recommend that the auctioning provisions be deleted from the bill. Further, the bill prohibits the use of fuel adjustment

Conclusion

In summary, American Electric Power recognizes that there are many environmental drivers for additional emissions reductions from our coal-fired power plants and is already planning for many of those reductions. However, it is critical that any EPA rules, such as the proposed Transport Rule, be structured in a way to allow for cost-effective implementation on a reasonable schedule so as to minimize the impacts on our customers and on the reliability of the electricity grid. It is also critical that the emissions reduction levels of the program be set at levels that are technically feasible to achieve over the given time frame and are in fact necessary to fulfill the air quality goals and requirements of the Act. Moreover, it is critical that such a program provide some certainty over future compliance obligations, as AEP and other electric utilities continue the transformation of the electric generating fleet in this country. As it is currently proposed, the Transport Rule does not achieve these objectives.

Finally, AEP would urge the Congress to consider adopting a multi-pollutant control program that can achieve the anticipated emissions reductions from the electric power sector over the next decade in a manner that is consistent with all of these objectives. AEP believes that such legislation would be a big win for the environment, our local economies across the nation, and the American people.

AEP would like to thank the Subcommittee for the opportunity to present the views of AEP on this important issue.

Senator CARPER. Thank you very much.

That would be a good goal to work toward. You and I have put a lot of time and energy into this. I know so has our former Chair, Senator Inhofe, and Lamar Alexander and others on the Committee.

A lot of people think we can't get much done this year and that we are just going to ride it out and just end up with delay and inability to find common ground. I am more hopeful, particularly in this area, that we can surprise some people. So let's give it a shot.

Our first witness, the entire panel is one person, one woman. It is Regina McCarthy, and she has been here a number of times before. We are grateful that you are willing to come back and to talk with us today.

EPA Assistant Administrator for the Office of Air and Radiation, I think you have been in this job for almost 18 months. It probably seems like 18 years. We thank you for your service and for your leadership, Gina.

Ms. McCarthy, you have 5 minutes to read your opening statement. The full content of your written statement will be included in the record, and you are recognized. Please proceed. Thank you for joining us.

STATEMENT OF REGINA MCCARTHY, ASSISTANT ADMINISTRATOR, OFFICE OF AIR AND RADIATION, U.S. ENVIRONMENTAL PROTECTION AGENCY

Ms. MCCARTHY. Thank you. It is great to be here, Chairman Carper, members of the Subcommittee. I thank you for inviting me to testify today on EPA's recently proposed Federal implementation plans to reduce interstate transport of fine particulate matter and ozone, which we call the Transport Rule, which we believe is an important step toward protecting public health, to helping States reduce their pollution, and to meeting our clean air standards.

Millions of people continue to breathe unhealthy air that does not meet our National Ambient Air Quality Standards. This is due to a combination of pollution from local and in-State sources as well as pollution from upwind States that cross State lines. As a result the Clean Air Act assigns responsibility to meet the Clean Air Standards to both upwind and downwind States. EPA's recently proposed Transport Rule addresses upwind States' responsibilities while States and local agencies must continue to work on local and in-State pollution control measures.

This transport rule represents a significant step that EPA is taking to help States implement the good neighbor provision of the Clean Air Act on an ongoing basis. It also fulfills our commitment to address interstate transport with the exact same urgency that we and other State partners bring to the local non-attainment planning obligations. From now on, each time a NAAQS is changed EPA will evaluate whether interstate pollution transport contributes to the air quality problem, and if so, whether new emissions reductions will be required from upwind States.

Our proposed Transport Rule would require significant reductions in SO_2 and NO_x emissions from power plants in 31 States and the District of Columbia. The first phase would take effect in 2012 in all 31 States and DC, with a second phase that would take effect in 15 States in 2014. By 2014 we project that power plant SO_2 emissions in the covered area will be 71 percent lower than 2005 levels, and power plant emissions of NO_x emissions will be 52 percent lower than 2005 levels.

The emission reductions required by the Transport Rule in upwind States will provide health and environmental benefits both in-State and in downwind States. We estimate that by 2014 it will prevent 14,000 to 36,000 premature deaths annually and provide more than $120 billion to $290 billion annual savings and benefits. These benefits will far outweigh the estimated annual cost of $2.8 billion in 2014. It will help all but a very few areas in the eastern part of the country come into attainment with the 1997 $PM_{2.5}$ and ozone standards and make major strides toward attaining the 2006 24-hour average $PM_{2.5}$ standard.

When final, the proposed rule will replace the Clean Air Interstate Rule which was remanded back to EPA in 2008. In response to the Court decision EPA went back to the drawing board and developed a new rule that reflects the Court decision. Compared to CAIR some of the major differences in the Transport Rule include more emission reductions in 2012 and 2014 and a definition of significant contribution that is based both on cost as well as downwind air quality impacts. We are closely adhering to the 2008 Court opinion with regard to establishing State budgets, interstate trading, use of title IV allowances, fuel factors, and other issues that the Court spoke to as well as developing a new methodology that can be applied to current and future NAAQS revisions.

As you are all well aware, this proposal is the first of several rules that EPA intends to issue over the next 2 years that will yield substantial public health and environmental benefits and maintain a reliable and affordable supply of electric power across the country. In developing and promulgating these rules the agency will be providing States with the help that they need to attain the NAAQS and providing the power industry with a much clearer picture of what EPA will require of it in the next decade.

As I have stated here before, my top priority is to work with you, with the power industry, with the other industry sectors, States, community groups and environmental groups, and with the full range of experts from government, business and universities to find the right path forward in crafting the laws and regulations we need to protect public health and the environment. I still believe that that is the most important responsibility I have right now.

And to that end, let me note before I close how much I appreciate the substantial contribution that Senator Carper and S. 2995 have made to the debate and to our shared goal of clean air. S. 2995 offers emission reductions that would provide significant benefits to the public, and it would maintain critical authorities in the current Clean Air Act that are designed to ensure that every American breathes air that meets health-based National Ambient Air Quality Standards.

I am confident that together we can make great strides to meet our shared goal. Thank you very much, and I am here to answer questions.

[The prepared statement of Ms. McCarthy follows:]

STATEMENT OF REGINA A. MCCARTHY
ASSISTANT ADMINISTRATOR
OFFICE OF AIR AND RADIATION
U.S. ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE SUBCOMMITTEE ON CLEAN AIR AND NUCLEAR SAFETY
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
U.S. SENATE
JULY 22, 2010

Chairman Carper, Ranking Member Vitter, and members of the Subcommittee, thank you for inviting me to testify today on EPA's recently proposed "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone." This rule, known as the "Transport Rule," is an important step towards protecting public health, helping states reduce air pollution, and meeting our clean air standards. In my testimony I will provide the committee with some details about this rule and the new approach it represents for EPA, as well as information on the likely benefits of the rule for the American people.

Millions of people continue to breathe air that does not meet our national air quality standards. This unhealthy air is due to a combination of pollution from local and in-state sources, as well as pollution from upwind states that crosses state lines and is transported long distances from its original source. The recently-proposed Transport Rule addresses the upwind state sources of pollution. It represents a significant step that EPA is taking to fulfill our commitment to help states implement the "good neighbor" provision of the Clean Air Act on an on-going basis and with the exact same urgency that we and our state partners bring to local nonattainment planning obligations.

EPA's proposed Transport Rule implements a new methodological approach that helps states meet their obligations to reduce transported pollution. The rule enables the provisions of the Clean Air Act that require upwind states to eliminate emissions that significantly contribute to air quality problems in downwind states. The proposed rule would require significant reductions in sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from power plants in 31 states and the

District of Columbia. These reductions are required to help downwind states to attain and maintain compliance with the current national ambient air quality standards for fine particles ($PM_{2.5}$) and ozone. As you all are well aware, SO_2 and NO_x both react in the atmosphere to form fine particles; NO_x also contributes to the formation of ground-level ozone. The health effects of exposure to elevated levels of $PM_{2.5}$ and ozone include premature death, more asthma symptoms in those already suffering from that disease, and respiratory and cardiovascular diseases that are often serious enough to require hospitalization.

The emissions reductions required by the Transport Rule in upwind states would provide health and environmental benefits both in-state and in downwind states. We estimate that by 2014 the proposed Transport Rule will prevent 14,000 to 36,000 premature deaths annually, as well as provide many other health and environmental benefits. The portion of these health and welfare benefits that can be quantified total more than \$120 to \$290 billion annually in 2014. These benefits will far outweigh the estimated annual costs of \$2.8 billion. The Transport Rule will help all but a very few areas in the eastern part of the country come into attainment with the 1997 $PM_{2.5}$ and ozone standards. In addition, the rule will make major strides toward helping states address nonattainment with the 2006 24-hour average $PM_{2.5}$ standard.

Controlling the interstate transport of pollution is important for several reasons. Interstate pollution transport increases pollution levels and health risks in the downwind state. From the standpoint of a downwind state, the pollution contribution of each upwind state adds up to a larger, cumulative degradation of the downwind state's air quality. The combined impact of pollution transport makes it necessary for the downwind state to obtain deeper pollution reductions to attain and maintain air quality standards, which increases costs of control in the downwind state and can delay or make it impossible to achieve the health-based air quality standards.

The proposed Transport Rule is designed to achieve reductions as quickly as possible to help states attain the 1997 ozone and $PM_{2.5}$ and 2006 $PM_{2.5}$ national ambient air quality standards (NAAQS). When final, this proposed rule will replace the Clean Air Interstate Rule (CAIR), which was designed to meet the same goal. However, the proposed Transport Rule is projected to result in more emission reductions in 2012 and 2014 than what we had anticipated achieving under CAIR. The most significant reasons for this include: reductions in the Transport Rule to address the 2006 $PM_{2.5}$ NAAQS; reductions in the Transport Rule to eliminate emissions that interfere with maintenance of the NAAQS in downwind states; our methodology for determining significant contribution; and the Transport Rule does not allow use of the large Title IV SO_2 allowance bank for compliance in early years.

A July 2008 court decision vacated CAIR; subsequently, in December 2008, the court decided to keep the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement the Clean Air Act requirements concerning the transport of air pollution across state boundaries. In response to the court decision, EPA went back to the drawing board and developed a new rule that reflects each aspect of the court's decision, which, in turn, reflects the essential elements of EPA's obligations under the Clean Air Act. The rule focuses on identifying and remedying each state's significant contribution to downwind air quality problems, and, as required by both the court and the Clean Air Act, focuses on improving downwind air quality.

With this proposed Transport Rule, EPA is proposing a new methodology for determining upwind state emission reduction responsibility that is designed to be applicable to current and potential future ozone and $PM_{2.5}$ NAAQS. This methodology uses a multi-step process to analyze both costs and air quality impacts, identify the cost thresholds appropriate for the circumstances specific to this rulemaking, quantify reductions available in each state at those thresholds, and consider the impact of variability in power plant operations. This methodology is based on cost <u>and</u> air quality considerations that are common to any NAAQS, but also calls for evaluation of facts specific to a particular NAAQS level. As a result, in the future EPA will consider whether it is reasonable to require larger reductions in transported pollution from upwind states in the case of a revised, more health-protective NAAQS.

The Clean Air Act requires states to submit plans to eliminate significant interstate pollution transport <u>before</u> they submit plans to meet ambient air quality standards. This allows downwind states to know how many upwind state reductions will be required when they design their plans to meet the NAAQS. When EPA announced the proposal of this Transport Rule, we also stated that we intend to follow this same process for addressing interstate transport of air pollution. From now on, each time a NAAQS is changed, EPA will evaluate whether interstate pollution transport contributes to the air quality problem, and, if so, whether new emission reductions will be required from upwind states. By determining the amount of emissions that upwind states must eliminate before state pollution transport plans are due, EPA will help the Clean Air Act to work as intended and help downwind states attain the health-based standards as soon as practical. EPA is undertaking a series of regulatory actions over the next 2 years that will affect the power sector in particular, as well as other sectors. For example, EPA has already begun the work necessary to apply the template proposed in the Transport Rule to the next ozone NAAQS. The Agency plans to quickly propose and finalize a transport rule to address that standard so that emission reductions can take place in time to help states attain the standard.

In addition, EPA is in the early stages of developing regulations under section 112 of the CAA that will require existing and new coal- and oil-fired power plants to meet emissions limits for mercury and other HAPs. Currently, we have a court-ordered deadline to issue a proposed rule for these sources by March, 2011, and issue a final rule by November, 2011. EPA anticipates that, as a result of these requirements, these power plants may also significantly reduce their emissions of SO_2.

Details about the Proposal

In the Transport Rule, EPA proposes to find that emissions of SO_2 and NO_x in 31 eastern states and the District of Columbia contribute significantly to nonattainment or interfere with maintenance in one or more downwind states. EPA is making this finding with respect to one or more of three air quality standards: the annual average $PM_{2.5}$ NAAQS promulgated in 1997, the ozone NAAQS promulgated in 1997, and the 24-hour average $PM_{2.5}$ NAAQS promulgated in 2006.

We are proposing a preferred approach, or remedy, to require power plants to reduce SO_2 and annual NO_x emissions in states that significantly contribute to downwind state $PM_{2.5}$ air quality problems, and to require power plants to reduce ozone-season NO_x emissions in states that significantly contribute to downwind state ozone air quality problems. In addition, we are taking comment on two proposed alternatives that we feel are consistent with the court decision. In all approaches, we propose to set a pollution limit (or budget) for each of the 31 states and the District of Columbia. The difference among the approaches is in how sources must comply with those budgets.

Our preferred approach allows both intrastate trading and limited interstate trading among power plants but assures that each upwind state will meet its pollution control obligations under the "good neighbor" provision of the Act. This results in four programs:

- a program to limit ozone season emissions of NO_x in 25 states and the District of Columbia beginning in 2012
- a program to limit annual emissions of NO_x in 27 states and the District of Columbia beginning in 2012
- two programs to limit annual emissions of SO_2: one program that limits emissions in 27 states and the District of Columbia beginning in 2012, and one that further limits SO_2 emissions in 15 of those states beginning in 2014.

In the first alternative approach, we propose to allow trading only among power plants within each state. In the second alternative approach, we propose to specify the allowable emission limit for each power plant and allow some averaging. In addition, EPA is taking comment on alternative approaches, including a trading ratio approach that would take into account differences in cumulative downwind impact of emissions from various states but would not assure upwind reductions within a certain state.

The Transport Rule proposes a new, state-specific cost and air quality methodology for determining the amount of emission reduction each upwind state must achieve to eliminate its significant contribution to downwind nonattainment. The proposed methodology uses air quality analysis to determine whether a state's contribution to downwind air quality problems is above specific thresholds. If a state's contribution does not exceed those thresholds, its contribution is found to be insignificant and it is no longer considered in the analysis. If a state's contribution exceeds those thresholds, EPA takes a second step that uses a multi-factor analysis that takes into account both air quality and cost considerations to identify the portion of a state's contribution that is significant or that interferes with maintenance. This second step of the methodology is a multi-step process that analyzes costs and air quality impacts, identifies appropriate cost thresholds, quantifies reductions available from power plants in each state at those thresholds, and considers the impact of variability in power plant operations.

As noted above, the first phase of emissions reductions in all 31 states and the District of Columbia would begin to take effect in 2012. Further emission reductions of SO_2 would take place in 15 of those states in 2014. If the Transport Rule is finalized as proposed, EPA projects that, by 2014, the proposed Transport Rule and other state and EPA actions would reduce power plant SO_2 emissions in 31 states and DC by 71 percent (6.3 million tons) compared to 2005 levels. Power plant NO_x emissions would drop by 52 percent (1.4 million tons). This includes reducing 300,000 tons of NO_x during the hot summer ozone season. In the states and DC covered by the proposed Transport Rule, in 2014, SO_2 emissions are projected to be 2.6 million tons per year annually and NO_x emissions would be 1.3 million tons per year. Ozone season NO_x emissions are projected be 600,000 tons per year. EPA anticipates that power plants may operate already installed control equipment more frequently, use low sulfur coal, or install control equipment such as low NO_x burners, selective catalytic reduction, or flue gas desulfurization to achieve these emission reductions. Many power plants began the process of contracting for and installing pollution control equipment and making other adjustments to their operations (e.g. switching to low-sulfur coal) that would reduce their emissions when CAIR was finalized in 2005.

To assure emissions reductions take place quickly, and to fulfill our legal obligations, EPA is proposing federal implementation plans, or FIPs, for each of the states covered by this rule. These plans would reduce air pollution that significantly affects another state. These replace the existing CAIR FIPs that have been remanded by the court. A state may choose to develop its own state implementation plan, or SIP, to achieve the required reductions for the 1997 ozone NAAQs, the 1997 $PM_{2.5}$ NAAQs, or the 2006 $PM_{2.5}$ NAAQs, or any combination of them. Once approved by EPA, any SIP developed by a state would replace the federal plan, and allow the states to choose which types of sources to control and how they should be controlled.

The reductions obtained through the Transport Rule FIPs will help all but a very few areas in the eastern part of the country come into attainment with the 1997 $PM_{2.5}$ and ozone standards. In addition, they will make major strides toward helping states address nonattainment with the 2006 $PM_{2.5}$ standard. In the case of some 1997 ozone and 2006 $PM_{2.5}$ downwind areas with projected nonattainment and maintenance problems, however, EPA was not able to fully define the level of significant contribution from each upwind state without further analysis. As a result, EPA is proposing the emission reductions our analyses have shown are necessary to eliminate significant contribution. At the same time, we are continuing to analyze whether more reductions might be needed for several 1997 ozone and all 2006 $PM_{2.5}$ nonattainment and maintenance areas. This decision not to delay the rule until the analyses are completed reflects EPA's obligation to respond to the court remand expeditiously and the importance of achieving emissions reductions to assist downwind attainment at the earliest practical dates.

EPA is working expeditiously to finish our analysis of these two issues. To the extent possible, EPA plans to finalize the Transport Rule with a full determination of, and remedy for, significant contribution and interference with maintenance for the 2006 $PM_{2.5}$ standard. In the case of the 1997 ozone standard, EPA intends to proceed as quickly as possible with additional rulemaking to fully address the residual significant contribution to nonattainment and interference with maintenance. At this time, we intend to work in parallel on this additional rulemaking and any additional reductions in interstate transport needed to address the upcoming 2010 ozone standard.

Benefits and Costs of the Proposal

SO_2 and NO_x contribute to the formation of fine particles. NO_x reacts with volatile organic compounds to form ground-level ozone. Both of these pollutants cause a series of human health effects and environmental damages, including premature mortality, chronic and acute bronchitis, heart attacks, hospitalizations, emergency room visits, asthma attacks, and lost days at work and school. The reductions in air pollution from the proposed Transport Rule would provide large health and environmental benefits. Assuming that all particulate matter species cause approximately the same harm per unit of mass, benefits would include annually preventing 14,000 to 36,000 premature deaths; 23,000 non-fatal heart attacks; 26,000 hospital and emergency room visits; 240,000 cases of aggravated asthma; and 1.9 million days of missed work or school. While no clear scientific grounds exist for supporting differential effects estimates by particle type, recent evidence suggests the possibility that PM mixtures with higher concentrations of black carbon and specific metals might be more potent than the average $PM_{2.5}$ mixture. Avoiding "sick days" may be particularly important for the millions of Americans whose jobs do not provide paid sick leave and who can be at risk of losing their jobs if they miss work too often. Other benefits include reductions in mercury emissions, acidification of lakes, streams, and forest soils, and eutrophication of estuaries and coastal waters.

The proposed rule would yield at least $120 to $290 billion in annual benefits in 2014. Most of these quantified benefits are public health-related, but $3.6 billion are attributable to visibility improvements, mostly in eastern national parks and wilderness areas.

These quantified and unquantified benefits far outweigh the estimated annual costs of $3.7 billion in 2012 and $2.8 billion in 2014. The modest cost of the proposed Transport Rule means only modest effects on electricity generation. EPA estimates that in 2014, as a result of this proposed rule, average electricity prices will increase less than 2 percent, natural gas prices will increase less than 1 percent, and coal use will be reduced by less than 1 percent. A portion of the Transport Rule emissions reductions will come from plants operating existing control equipment that--without the Transport Rule--would not be required to operate; this contributes to the modest cost of the proposal.

Transport Rule and CAIR

EPA has been working to reduce interstate transport in regards to the 1997 ozone and $PM_{2.5}$ standards since the NO_x SIP Call was first issued in 1998. The Clean Air Interstate Rule (CAIR), which requires similar but fewer emission reductions as those in the proposed Transport Rule, was proposed in 2003 after several years of data collection and analysis, including extensive input from stakeholders, and finalized in 2005 (70 FR 25162). CAIR requires initial emission reductions from power plants for NO_x in 2009 and SO_2 in 2010; additional reductions of both pollutants are required in 2015.

In July 2008, the D.C. Circuit Court found CAIR unlawful (North Carolina v. EPA, 531 F.3d 896 (D.C. Cir. 2008)). The court first vacated CAIR but then remanded it to EPA without vacatur to "preserve the environmental values covered by CAIR" (North Carolina v. EPA, 550 F.3d 1176, 1178 (D.C. Cir. 2008)). As a result of the remand, the CAIR requirements remain in place while EPA develops replacement rules.

As I noted earlier, when CAIR was finalized in 2005, many power plants began the process of contracting for and installing pollution control equipment and making other adjustments to their operations (e.g. switching to low-sulfur coal) that would reduce their emissions. Many power plants had already begun operating that equipment in 2008 when CAIR was remanded; many more power plants were preparing to reduce their emissions within the next few years in anticipation of the CAIR compliance deadlines. These pollution control investments will now be used to meet the emission reduction requirements under the Transport Rule.

EPA anticipates that, under the proposed Transport Rule, power plants will meet the 2012 requirements by operating control equipment installed to meet CAIR requirements more frequently, using lower sulfur coal, or installing simple pollution control equipment such as low NO_x burners. By 2014, when the more stringent SO_2 emissions limits take effect, we project that some sources will install scrubbers (flue gas desulfurization) on approximately 14 gigawatts worth of coal-fired plant capacity.

Although the proposed Transport Rule takes advantage of, and expands upon, the pollution control investments made under CAIR, it is fundamentally different from CAIR in several important ways. These differences reflect the court's concerns with CAIR. EPA believes that each option proposed in the Transport Rule is consistent with court opinions interpreting the requirements of CAA section 110(a)(2)(D)(i)(I).

First, the methodology used to measure each state's significant contribution to another state emphasizes air quality as well as cost considerations and uses state-specific data and information. Second, the proposal gives independent meaning to the phrase "interfere with maintenance" in section 110(a)(2)(D) of the Clean Air Act. Third, the state budgets for SO_2, annual NO_x, and ozone season NO_x are directly linked to the measurement of each state's significant contribution and interference with maintenance.

Fourth, the proposed remedy includes provisions to assure that all necessary reductions occur in each individual state. EPA proposes to allow within-state trading and limited interstate trading in a manner that ensures that each upwind state achieves its required emission reductions. Finally, the compliance deadlines are coordinated with the attainment deadlines for the relevant NAAQS.

Summary and Conclusion

This proposed Transport Rule recognizes that the Clean Air Act assigns responsibility to meet the clean air standards to both upwind and downwind states. This Transport Rule addresses upwind state responsibilities; at the same time, states and local agencies continue to work on local and in-state pollution control measures.

This proposal is the first of several rules EPA intends to issue over the next 2 years that will yield substantial health and environmental benefits for the public primarily through regulation of power plants. EPA expects that this set of requirements will yield substantial health and environmental benefits for the public, benefits that can be achieved while maintaining a reliable and affordable supply of electric power across the economy. In developing and promulgating these rules, the Agency will be providing the power industry with a much clearer picture of what EPA will require of it in the next decade. In addition to promulgating the rules themselves, the Agency will engage with other federal, state and local authorities, as well as with stakeholders and the public at large, with the goal of fostering investments in compliance that represent the most efficient and forward-looking expenditure of investor, shareholder, and public funds, resulting, in turn, in the creation of a clean, efficient, and modern power sector.

The comment period for the proposed Transport Rule will run for 60 days from the date of publication in the *Federal Register*, which will likely take place at the beginning of August. In addition, we plan to hold three public hearings on the rule. We will provide details on the timing and location for those hearings shortly in a *Federal Register* Notice.

As I have stated here before, my top priority at EPA is to work with you, with the power industry and other industry sectors, with the states, with community groups and environmental groups, and with the full range of experts from government, business, and universities to find the right path forward in crafting the laws and regulations needed to protect human health and the environment. I still believe that is the most important responsibility I have right now.

In closing, I would like to thank Senator Carper and other members of the committee for your strong leadership on these issues over the years. I am confident that we can make great strides to meet our shared goals.

Thank you. I look forward to answering your questions.

Environment and Public Works Committee Hearing
July 22, 2010
Follow-Up Questions for Written Submission

Questions for McCarthy

Questions from:

Senator Bernard Sanders

1. Please compare, both nationally and for Vermont, the pollution reduction targets and timetables and health impacts for air pollutants under S. 2995, and under a scenario in which no new legislation is adopted and EPA proceeds with its existing authority.

Answer:

Emissions Caps and Timing in Proposed Transport Rule and S.2995

SO_2	Transport Rule (Covered States Only)	S. 2995 (Nationwide)
SO_2 emissions cap in 2012	3.9 million tons (MT)	3.5 MT
SO_2 emissions cap 2014/2015	2.5 MT *(+MACT)*	2.0 MT
SO_2 emissions cap in 2018	No Change	1.5 MT
NO_x		
Seasonal NO_x 2012-2014	0.64 MT	Maintains CAIR program; projected at 800,000 tons in covered states through 2014
Annual NO_x emissions in 2012	1.4 MT	1.9 MT
Annual NO_x emissions in 2015	No Change	1.6 MT

There are no state-specific emissions caps in S. 2995. There are no state-specific emissions caps for Vermont in the proposed Transport Rule, as Vermont was not found to contribute to nonattainment or interference with maintenance in downwind states.

Health Impacts for Air Pollutants
The recently proposed Transport Rule is one of a number of rules EPA will be issuing over the next few years that will address the problem of ozone and PM2.5 nonattainment. Because of this, comparing one of those rules, the Transport Rule, to S. 2995 gives a misleading impression of what emission reductions will take place past 2015.

In addition, differences in the modeling done by EPA to analyze the impacts of the Transport Rule and S. 2995 are an apples-to-oranges comparison. For example, the S. 2995 modeling uses different IPM baseline assumptions and projections including:

- Lower electricity demand projections reflecting ARRA provisions added in mid-2009.
- Changes in generation resources, especially different renewable assumptions accounting for ARRA provisions

- Updated Title IV bank projections reflecting the assumption of full CAIR implementation (whereas the Transport Rule modeling assumes no CAIR)
- Additional updates of state settlements and state power sector rules

2. Which, if any, pollutants would be covered under EPA's existing authority that are not covered under the approach outlined in S. 2995?

Answer:

S 2995 regulates sulfur dioxide, nitrogen oxides and mercury. In addition to these three pollutants, EPA's existing authorities cover numerous other pollutants, including $PM_{2.5}$, PM 10, carbon monoxide, volatile organic compounds, hazardous air pollutants (besides mercury), and greenhouse gases.

3. Does EPA believe additional legislative authority, such as is provided under S. 2995, is necessary to achieve our national and state air pollution objectives?

Answer:

The Clean Air Act provides EPA and states authority under the CAA to address power plant emissions. This authority has been used effectively in the past. Air quality has improved markedly since 1990 because of power plant regulation and other CAA required controls. We have plans for interstate pollution transport rules and section 112 standards for electric generating units (EGU) that will further reduce power plant emissions. EPA is not recommending new legislation at this time.

Senators James M. Inhofe and George V. Voinovich

1. Proposed provision 417 (a)(3) of S. 2995 would appear to provide EPA with broad authority to reduce the seasonal ozone nitrogen oxides budgets. Proposed subparagraph (3)(B) of this section includes several criteria for EPA to use in making this determination, including the need to assist States in attaining and maintaining National Ambient Air Quality Standards (NAAQS) and the need to assist States in meeting their obligations under Section 110(a)(2)(D). Subparagraph (3)(B) also allows EPA to reduce the NOx budgets in order "to protect public health or the environment." Please provide to the Committee any reason why EPA would need the additional broad authority included in Subparagraph 3(B)(i) to further reduce NOx budgets for reasons that are not already included in subparagraph (3)(B). Similarly, if there are reasons for including this authority, please explain why other provisions in the Clean Air Act are not sufficient to address the concerns.

   Answer:

   The language in question explicitly provides that reducing the NOx budgets is a tool EPA may use to protect public health and the environment.

2. As mentioned above, S. 2995 proposes to provide EPA with the authority to consider the effect of one State's emissions on the ability of another State to attain or maintain NAAQs in determining the need for reducing state emissions budgets. If S. 2995 is enacted, how would this impact EPA's response to Section 126 petitions by States seeking to require reductions at specific units in upwind States?

   a. How would EPA's response to Section 126 petitions change if EPA finalizes its proposed Clean Air Transport Rule? Would electric generating units covered by the proposed transport rule still be vulnerable to these petitions?

Answer:

By substantially reducing interstate transport of SO_2 and NO_X, and with the associated reductions in particulate matter and ozone, S. 2995 and the Transport Rule, if finalized as proposed, would greatly reduce the likelihood that an electric generating unit would be subject to a section 126 petition. However, neither S. 2995 nor the Transport Rule would prevent a state from filing a section 126 petition if it believes any stationary source or group of stationary sources is still contributing to a specific nonattainment or maintenance problem.

3. Proposed Section 417(a)(3)(A) of S. 2995 would also allow EPA to lower the ozone nitrogen budget for nonelectric generating units. Please provide a list of all the existing nonelectric generating unit budgets that could be subject to further reductions under this paragraph. Does EPA currently have any plans for establishing nonelectric generating unit budgets or requiring States to do? If so, please provide a detailed description.

Answer:

EPA is considering the need for additional non-EGU budgets and requirements in the context of a second transport rule addressing the upcoming reconsidered ozone standard.

For the Transport Rule proposed in August 2010, EPA noted that it would be addressing whether further nitrogen oxide reductions were necessary to eliminate significant contribution to nonattainment or interference with maintenance for the 1997 ozone standards for three locations: Baton Rouge, Houston, and New York City. If further reductions are needed from non-EGU sources for states contributing to these three locations, EPA expects to achieve those reductions though the second transport rule.

4. EPA currently has a voluntary program to promote cogeneration use. According to EPA's web site, the Combined Heat and Power (CHP) Partnership program seeks to reduce the environmental impact of power generation by promoting the use of CHP, also known as cogeneration. What are the main benefits of using cogeneration compared to fossil fuel-fired generation?

Answer:

The average efficiency of fossil-fueled power plants in the United States is 33 percent and has remained virtually unchanged for four decades. This means that two-thirds of the energy in the fuel is lost—vented as heat—at most power plants in the United States. By using waste heat recovery technology to capture a significant proportion of this wasted heat, CHP systems typically achieve total system efficiencies of 50 to 80 percent for producing electricity and thermal energy. Because CHP is more efficient, less fuel is required to produce a given energy output than with separate heat and power. Higher efficiency translates into lower operating costs and reduced emissions of all pollutants. In addition, CHP, as a distributed generation source also brings other advantages to its use, such as increased reliability and power quality and reduced grid congestion and avoided distribution losses.

   a. Please describe the major differences in the treatment of cogeneration units between S. 2995 and the recently proposed Clean Air Transport Rule and Title IV of the Clean Air Act.

Answer:

The definition and treatment of cogeneration units are different under Section 419(a) of S.2995, the Acid Rain Program under CAA Title IV, and the proposed Transport Rule programs.

Under Section 419(a) of S.2995, cogeneration units do not receive different regulatory treatment than other types of electric generating units. "Cogeneration unit" and "cogeneration facility" are not defined. Any facility (including a cogeneration facility) that on or after January 1, 1985, serves a generator with nameplate capacity greater than 25 MWe and produces electricity for sale is subject to the regulatory requirements of the NOx program.

Under the Acid Rain Program (CAA Title IV), some cogeneration units receive different regulatory treatment than other types of electric generating units. The Acid Rain Program rules define "cogeneration unit" as a unit with equipment to produce electricity and useful thermal energy (e.g., steam for industrial processing) through sequential use of energy. The following categories of cogeneration units are exempt from the Acid Rain Program: (i) those that are qualifying facilities under the Public Utility Regulatory Policies Act (PURPA) and have fixed-price power purchase contracts for at least 15% of planned net capacity that were in place as of November 15, 1990 and continue to be in place without changes allowing for pass-through of Acid Rain Program compliance costs (CAA section 405(g)(6)(A) and 40 CFR 72.6(b)(5)); and (ii) those that sell to the grid an annual average amount (on a 3-year rolling average basis) of electricity less than or equal to 1/3 of their potential electrical output capacity or less than 25 MWe (i.e., 219,000 MWhr) (CAA section 402(17)(C) (definition of "utility unit") and 40 CFR 72.6(b)(4)).

Under the proposed TR trading programs, some cogeneration units -- but fewer than under CAA Title IV – receive different regulatory treatment than other types of electric generating units. The proposed TR trading program rules define "cogeneration unit" as a unit: (1) with equipment to produce electricity and useful thermal energy (e.g., steam for industrial processing) through sequential use of energy; and (2) meeting certain operational and efficiency standards. The following category of cogeneration units is exempt from the proposed TR trading programs: those that sell to the grid an annual amount of electricity less than 1/3 of their potential electrical output capacity or less than 219,000 MWhr. This definition is the same as was used in the CAIR program (40 CFR 97.104(b)(1)).

The similarities in the provisions of S. 2995, the proposed Transport Rule (TR), and Title IV of the Clean Air Act, are the following:

- All three refer to cogenerating units greater than 25 MW in capacity in their consideration of energy generating units.
- All three address the impact of two pollutants - NOx and SO_2 – both criteria pollutants under the Clean Air Act.

The major differences in the three are as follows:

- The proposed TR and Title IV exempt the subset of these cogeneration systems that sell less than a third of their output to the grid from their requirements. S. 2995 does not include such an exemption and therefore applies to more cogenerating facilities.
- S. 2995 establishes limits for mercury in addition to NOx and SO_2

b. How many more cogeneration units would likely be subject to regulation under S. 2995 when compared to EPA's recently proposed CATR rule? Where are many of these cogeneration units located? What industries or commercial operations could be impacted under S. 2995 if the definition is not changed?

Answer:

Preliminary analysis shows that nearly 80 cogeneration facilities with a total capacity of over 15,000 MW are subject to limits for SO_2 and/or NO_X under Title IV. A subset of these are subject to SO_2 and/or NO_X limits under the TR, as proposed. In contrast, S.2995 would cover around 300 facilities with a total capacity of approximately 36,000 MW. These are facilities primarily in the paper, refining and chemicals industries. Based on capacity, these facilities are primarily located in Texas, Louisiana and California. Based on the number of facilities, these facilities are predominantly located in California, Texas and Florida. (Note that California is not affected under the Transport Rule.)

c. How will S. 2995's treatment of cogeneration units impact the further use of cogeneration as source of efficient power?

Answer:

EPA has not performed a detailed analysis assessing the impact of S.2995 on cogeneration units. But we believe that more cogeneration facilities will be affected by the requirements of S. 2995, than the Acid Rain provisions and the proposed TR rule.

5. Based on full-scale commercially demonstrated test results, does EPA have sufficient information to determine that *all* coal-fired utility units in this country can meet a 90 percent reduction in mercury emissions on a unit-by-unit basis? If not, when will EPA have such information? Please explain.

Answer:

EPA does not, at this time, have sufficient data to determine whether all coal-fired utility units in the United States can achieve a 90 percent reduction in mercury emissions on a unit-by-unit basis. We currently have underway an information collection effort that will provide us with additional mercury emissions data from coal-fired utility units; this effort is in support of the section 112(d) rulemaking action. The proposed rule must be signed by March 16, 2011. However, even after we gather this data we may not have information that shows all coal-fired units in the country can meet a 90% mercury emissions limit on a unit-by-unit basis.

6. What is the predicted accuracy and reliability of current monitoring technology for mercury emissions for each major coal type? Has EPA studied the effectiveness of the mercury monitors in use for each coal type? If so, over what time period were they assessed? Please provide the Committee with a summary of these results.

Answer:

The Agency, in cooperation with electric utilities, conducted a testing program that evaluated mercury monitoring systems against reference methods using stringent accuracy requirements. The monitoring systems routinely passed all accuracy requirements for a variety of coals. Based on the testing program results, the Agency included monitoring protocols in the Clean Air Mercury Rule, issued in 2005, on the basis that mercury monitoring systems provided sufficient accuracy and high reliability. While the Clean Air Mercury Rule was vacated by the DC Circuit in 2008, most of the facilities that would have been required to monitor mercury emissions under this rule have installed mercury monitoring systems. Many of these mercury monitoring systems have been in continuous field operation across the U.S. since 2003 and have achieved 90% or greater availability (see NESCAUM, Technologies for Control and Measurement of Mercury Emissions from Coal-Fired Power Plants in the United States: A 2010 Status Report, Northeast States for Coordinated Air Use Management). Information collected from leading manufacturers of continuous mercury monitors indicates that over 600 mercury monitoring systems have been purchased and over 500 systems have been installed by electric utilities to date. Additionally, several States have implemented mercury regulations that require monitoring, and collect high quality mercury emission data using these monitors.

7. Under S. 2995, would EPA require a 90 percent reduction in mercury emissions for units for which pollution control venders will not provide guarantees of the performance of their technologies to meet those levels? Please explain. How does this process differ from the current MACT process in 112(d)?

Answer:

S. 2995 would require EPA to issue standards that ensure at least a 90 percent reduction in emissions from the source category. We would consider available information, including emissions data, and could also consider information from the manufacturers of the control equipment.

Currently under section 112(d), based on the language of this provision and on how it has been interpreted by the DC Circuit, EPA would not set a standard that required a certain percent reduction from each facility. Rather we would, under 112, set a standard that was based on an emissions rate that was achieved by the better performing facilities, EPA would also take variability into account when setting the standard under section 112(d).

8. In setting MACT standards generally, EPA appears committed to evaluating the average of the top 12 percent for each pollutant on an individual basis. This approach, however, may result in groupings of control technologies that are incompatible or infeasible at some plants. How does EPA propose to address issues of infeasibility and incompatibility?

9. Does EPA believe that the Clean Air Act provides the Agency with the authority under Section 112 to set standards that will force the closure of plants if the standards are not attainable by individual units?

Answer 8 & 9:

EPA is committed to setting 112(d) standards that follow the law, based on the language of the Clean Air Act and how it has been interpreted in recent court decisions, to make the best decision possible to protect public health. Public health protections in this part of the law are designed to prevent cancers and deaths from toxic air emissions. Where the law allows consideration of plant-specific designs we will consider this information if it has been provided to the Agency. EPA seeks to write protective standards that, where appropriate, take into consideration economic and plant-specific designs.

Currently under section 112(d), based on the language of this provision and on how it has been interpreted by the DC Circuit, EPA would not set a standard that required a certain percent reduction from each facility. Rather we would, under 112, set a standard that was based on an emissions rate that was achieved by the better performing facilities, EPA would also take variability into account when setting the standard under section 112(d).

10. Is EPA conducting any internal analysis of the cumulative impacts of currently anticipated Clean Air Act and Clean Water Act regulations over the next five to ten years on the utility industry? If not, why not? If so, please provide the committee with the estimated timeline of when the results of this study will be made available.

Answer:

EPA shares your interest in issues involving cumulative economic impacts, as well as the large cumulative health and environmental benefits, of future rules to reduce pollution from power plants. We cannot prejudge the results of future rulemakings, so we have not analyzed impacts of future rules not yet proposed. However, we have performed preliminary analysis of a scenario involving substantial additional air pollution controls. This scenario did not include any new water pollution controls. Since the preliminary analysis, we have updated our IPM model and key economic inputs such as natural gas prices. EPA published a Notice of Data Availability on its updated power sector modeling platform in the Federal Register on Sept. 1 (p. 53613). This new power sector modeling platform includes updated unit level input data (the National Electric Energy Data System (NEEDS v4.10)) and a set of model run results with the updated modeling platform (Integrated Planning Model (IPM) v4.10), detailed documentation of the updated version of the model, and user guides to input assumptions and model outputs.

We are in the very early stages of developing an improved pollution control scenario analysis with the updated model and inputs, and we are soliciting comments from other federal agencies on how to conduct this analysis. Because of the iterative nature of this process, we do not yet have an estimated completion date. We look forward to sharing analysis as rules are formulated in timely manner.

11. How many nonattainment areas are likely to be subject to fees under section 185 of the Clean Air Act based on current standards? Please list those areas. How many additional areas could be subject to Section 185 fees if the eight-hour ozone standard is lowered to 0.070 ppm or 0.060 ppm? Please list those areas.

Answer:

CAA Section 185 requires Severe or Extreme nonattainment areas to implement a rule to collect emissions fees if the area fails to attain the ozone standards. There are 4 remaining nonattainment areas for the 1-hour ozone NAAQS that are still classified as Severe or Extreme where the Section 185 requirements apply due to failure of the area to attain the 1-hour ozone NAAQS by the required attainment date.

- Sacramento Metro, CA – Severe 15 nonattainment area
- Riverside Co. (Coachella Valley), CA – Severe 15 nonattainment area
- Los Angeles South Coast Air Basin, CA – Extreme nonattainment area
- San Joaquin Valley, CA – Extreme nonattainment area

For the 1997 ozone NAAQS, there are currently 5 areas classified as Severe or Extreme and Section 185 requirements may apply in the future if the area fails to attain the 1997 8-hour ozone NAAQS by the required attainment date.

- Sacramento Metro, CA – Severe 15 nonattainment area

- Riverside Co. (Coachella Valley), CA – Severe 15 nonattainment area
- Los Angeles South Coast Air Basin, CA – Extreme nonattainment area
- Houston-Galveston-Brazoria, TX – Severe 15 nonattainment area
- San Joaquin Valley, CA – Extreme nonattainment area

For the 2008 ozone NAAQS (.075 ppm) that was promulgated in March 27, 2008 (73 FR 16436), EPA did not finalize nonattainment designations or classifications since EPA is in the process of reconsidering that ozone NAAQS.

For a revised NAAQS, EPA has not yet established a classification system for designated nonattainment areas. Therefore we are unable to predict whether any additional areas could be subject to future Section 185 fees based on the area's classification. EPA will propose alternative classification systems in an upcoming Ozone Implementation Rule for the NAAQS.

12. My understanding is that EPA is also proposing to increase the number of ozone monitors. Please provide the Committee with an estimate and timeline for the number of new monitors and the number of new areas that will be monitored for the first time.

Answer:

EPA proposed revised ozone monitoring requirements in 2009. The proposal addresses possible changes to the nation's ozone monitoring network necessitated by the 2008 ozone NAAQS revisions. Ozone monitoring requirements are based on the population of Metropolitan Statistical Areas (MSAs) and most recent air quality data. MSAs with air quality concentrations greater than or equal to 85% of the NAAQS have greater monitoring requirements. Based on the proposed monitoring requirements and latest ambient measurements from 2007-2009, we expect that 81 MSAs would have to initiate ozone monitoring for the first time. In addition, the monitoring proposal addresses the need for additional monitors in non-urban areas such as sensitive ecosystems and less populated Micropolitan Statistical Areas. While it is too early to provide an accurate count of exactly how many non-urban and less populated areas will have to monitor for the first time, the proposed rule estimated that up to 159 new monitors might be needed to meet these non-urban requirements, many of them in the West. Based on the timing of expected completion of the ozone monitoring final rule, we anticipate the installation of any new monitors would be phased in over two years: 2013 and 2014.

In addition, if EPA tightens the current ozone NAAQS level below 0.075 ppm as part of the current reconsideration of the 2008 ozone NAAQS, present ozone monitoring requirements will increase for certain MSAs. However, EPA estimates that no more than two MSAs will be required to add one additional monitor each to their existing ozone networks. Affected states will be required to meet these requirements in 2012.

These potential increases in the number of ozone monitors required nationwide represent a modest incremental extension to the current network of roughly 1,300 active monitors.

13. Based on current data including modeling data and CASNET data and other information available, how many additional areas of the country does EPA believe would likely violate an eight –hour ozone standard at 0.070 ppm if the area had a monitor? How many additional areas at 0.060 ppm? What is the likelihood that most of the country would violate the lower end of the proposed ranges for the primary and secondary standard if all counties in the US had monitors? Please explain. Please provide any updated charts or weblinks in your response.

Answer:

Based on 2007-2009 monitoring data, 420 counties would exceed a 0.070 ppm standard and 655 counties would violate a 0.060 ppm standard.

Attachment 1 (County Primary Ozone Levels 07-09.xls) gives a list of the 420 counties projected to exceed a 0.070 ppm standard (dark blue) and the additional 235 counties projected to exceed a 0.060 ppm standard (light blue) during the 2007-2009 monitoring period.

These estimates for counties with violating monitors at 0.070 ppm and 0.060 ppm reflect ozone data collected at the 23 CASTNET sites where the National Park Service operates the ozone monitors.

Based on 2002 emissions and air quality data, EPA projects a notable decrease in the number of counties with monitors projected to violate the eight-hour ozone standard at either level in 2020. Specifically, EPA projects that 99 counties with monitors would violate a0.070 ppm standard and 451 counties would violate a 0.060 ppm standard in 2020.

Attachment 2 (CountyOzoneLevels2020primary.pdf) gives a list of the 99 counties with monitors projected to exceed a 0.070 ppm standard (dark blue) and the additional 451 counties with monitors projected to exceed a 0.060 ppm standard (light blue) in 2020.

Other than measurements from ambient air quality monitoring sites, EPA does not have any other type of data from which we would be comfortable making estimates of how many additional counties could be in violation of the proposed ozone standards if a monitor were present. All the methods EPA uses for official purposes to characterize current or to predict future ozone attainment status are based on ambient air quality data from ozone. Even our modeling used to estimate future ozone levels is limited to areas with existing air quality monitors and is based on adjustment to the measurement data from those monitors.

14. What is the estimated cumulative parasitic energy cost of the control technologies that will be required to meet the reduction targets in S. 2995 or EPA's likely alternative regulatory approach? What will this mean in terms of increased greenhouse gas emissions? Which pollution control technologies require the greatest energy to run?

Answer:

Control equipment hierarchal energy consumption is as follows: Wet Flue Gas Desulfurization (FGD) > Dry FGD > SCR > SNCR > ACI. A wet FGD exhibits a 1.9% parasitic energy demand (ref: p.35-11, Table 6; "Steam: its Generation and Use"; 41st edition) while an SCR utilizes roughly 0.3% for auxiliary loads. In comparison, SNCR and ACI have much lower demands. Emission controls equipment consumes station power (defined as a parasitic loss or load) that would otherwise be used for electrical distribution. For a retrofit, the control equipment

subtracts from the station's net power output; consequently requiring the "grid" to replace power. The electrical grid's individual members increase their power output to offset the parasitic losses, thereby resulting in additional CO2 emissions. Since the grid's generation mix and power capacity vary with time (and subsequently emissions per unit energy), predicting the exact unit source for replacement power becomes problematic. On the other hand, the IPM tool projects annual aggregate (national) pollution emissions reflecting optimal market conditions for a mixed system of generation suppliers (coal, oil, gas, nuclear, wind, hydro, other) based on EIA projections for future power generation capacity (the grid). In short, the grid represents a pollution rate per GW, which permits derivation of CO2 contribution from retrofits. To determine the increased CO2 attributable to retrofits, their cumulative parasitic power load is multiplied by the aggregate annual pollutant contributed by the generation mix per unit power, or:
[(parasitic pwr%) * (GW retrofitted) *(nationwide annual CO2 tons / total GW produced)].

The net change in GHG emissions depends upon what type of replacement power is used. For example, year 2025 represents the highest retrofit cumulative parasitic power demand at 1.408 GW (1358.8 MW + 49.7 MW) while national power capacity projections are 1098 GW; in terms of CO2, parasitic power represents 3.30 million metric tons while nationwide power sector projections are 2,549 million metric tons – or 0.13%. In short, the CO2 associated component from replacement power (grid) is insignificant compared to nationwide fleet CO2 emissions.

Carper vs Base			
2012	2015	2020	2025
National CO2 (millions of metric tons)			
2,346	2,352	2,454	2,549
Nationwide Generation Capacity (GW)			
1,054	1,028	1,044	1,098

To illustrate the difference between S. 2995 Base Case and S.2995 Policy Case, the following tables list control equipment power demands with equivalent CO_2 produced to off-set parasitic power losses.

Retrofit Cumulative Parasitic Power Demand (MW) DELTA (S.2995 Policy Case– S.2995 Base Case)				
Year	2012	2015	2020	2025
FGD	118.4	342.6	788.4	1358.8
SCR	5.6	19.1	39.7	49.7

The additional CO2 emissions are based on the generation mix (coal, oil, natural gas, nuclear) as projected by IPM for that calendar year. Thus, the replacement power for parasitic loads comes from the available national fleet mix.

Increased CO_2 Emissions from Replacement Power (12/7/10) (Million Metric Tons CO_2)				
Year	2012	2015	2020	2025

FGD	0.27	0.79	1.86	3.18
SCR	0.01	0.04	0.09	0.12
total	0.28	0.83	1.95	3.30

Power plant efficiency improvements would moderate, and could offset, emissions increases associated with the parasitic load of these control technologies, and could be one element in a broader state effort to meet the National Ambient Air Quality Standards.

To illustrate the difference between the Proposed Transport Rule Base Case and the Proposed Transport Rule Remedy, see the following equivalent tables:

Retrofit Cumulative Parasitic Power Demand (MW) DELTA (Proposed TR – Proposed TR Base Case)				
Year	**2012**	**2015**	**2020**	**2025**
FGD	592.0	774.6	729.0	730.1
SCR	5.1	7.9	7.6	7.6

Increased CO_2 Emissions from Replacement Power (12/7/10) (Million Metric Tons CO_2)				
Year	**2012**	**2015**	**2020**	**2025**
FGD	1.45	2.02	1.93	1.89
SCR	0.01	0.02	0.02	0.02
Total	1.46	2.04	1.95	1.91

15. The CATR is intended to help the states meet the CAA Section 110 "good neighbor" provisions to eliminate significant contributions to downwind non-attainment and interference to maintenance. The CATR proposes to do this for the 1997 8-Hour Ozone NAAQS, the 1997 PM2.5 annual NAAQS, and the 2006 24-hr PM2.5 NAAQS. EPA is also proposing to lower the Ozone NAAQS to levels that EPA describes as unattainable with application of all known control measures for as many as 80 areas of the country, including parts of California. For many nonattainment areas, such as areas in Arkansas, Colorado, Illinois, Ohio, Pennsylvania, and West Virginia, emission reductions that will be required for unknown technologies far exceed those required by known technologies.

a. Please provide a list of all control technologies that EPA considers as "known" including estimates of their average and marginal cost. Does EPA consider restrictions in vehicle miles traveled or restrictions on generation or manufacturing production as "known" controls?

Answer:

EPA does not agree with the statement, "EPA is also proposing to lower the Ozone NAAQS to levels that EPA describes as unattainable with application of all known control measures for as many as 80 areas of the country, including parts of California. For many nonattainment areas, such as areas in Arkansas, Colorado, Illinois, Ohio, Pennsylvania, and West Virginia, emission reductions that will be required for unknown technologies far exceed those required by known technologies."

EPA's Regulatory Impact Analysis (RIA) includes a <u>range</u> of estimates for both the costs and benefits of attaining the revised Ozone NAAQS. These estimates, which reflect systematic consideration of a range of underlying assumptions and values, are intended for illustrative purposes only. Attachment A contains the list, prepared by EPA, of NOx control measures that are used in EPA's RIA analysis. It includes control measures and average cost estimates for stationary sources of NOx, and therefore does not include control measures for mobile sources or for sources of VOC emissions. This list is incomplete and we are working to add control measures for mobile sources and VOC emissions. When we finish with this effort, we intend to provide the VOC and NOx control measure lists to states to assist them in developing control plans.

EPA has also published in a series of documents known as control technique guidelines or CTGs for a limited set of source types. Each CTG deals with a particular industry and describes the control technologies which are applicable to emissions from that industry along with costs of controls. Copies of these CTGs are found at this web site: http://www.epa.gov/ttn/naaqs/ozone/ctg_act/index.htm. The CTGs contain estimates of the average costs for installing and operating emissions controls at sources that were previously uncontrolled.

EPA does not consider any specific restrictions on VMT, electricity generation or manufacturing production as "known" controls. EPA is aware of strategies states can implement to encourage reductions in VMT and reductions in electricity generation through energy efficiency measures. These strategies have already been successfully employed in some areas.

b. What types of control technologies are under development that could further assist these areas reach attainment over the next five to ten years? Please provide estimates of their costs.

Answer:

EPA does not comprehensively track the development of all future control technologies. However, history clearly indicates that the efficiency of current control technologies is always evolving to achieve greater reductions and lower costs. Similarly, production processes are constantly improving to reduce energy use and toward producing less waste and pollution. Finally, new technologies are developed to reduce pollution control costs. Indeed, EPA air standards that provide greater health protection for millions of Americans have resulted in numerous technological advances which have achieved lower pollution levels at lower than expected costs.

c. What is the likelihood that most of these areas will end up as either a severe or extreme nonattainment area?

Answer:

This will depend on a revised NAAQS, for which EPA has not yet established a classification system for designated nonattainment areas. Therefore we are unable to predict whether any additional areas would be classified as severe or extreme areas. EPA will propose alternative classification systems in an upcoming Ozone Implementation Rule for the NAAQS.

d. Does the Clean Air Act ever require EPA to sanction areas for failing to meet attainment if they have installed all known controls?

Answer:

Newly designated areas are expected to submit a State Implementation Plan (SIP) which demonstrates attainment by the required deadline. If a State fails to submit such a plan or submits an inadequate plan, EPA may disapprove the plan, which could result in CAA-prescribed sanctions. Sanctions can be avoided if the State submits an adequate plan before the sanctions deadline (18-24 months). If, in spite of reasonable planning efforts, an area fails to meet an attainment deadline, the CAA provides that the area receive a higher classification and is given additional time to further plan for and achieve attainment. The highest classification of Extreme provides up to 20 years for an area to attain. If an area fails to attain within 20 years after implementing all known control measures, Section 185 of the CAA requires the area to begin implementing an emissions fee program for major stationary sources.

16. EPA is currently considering significant reductions in the current ozone standard to levels that many believe approach ozone background concentrations. How would EPA interpret and enforce a State's obligation under Section 110(a)(2)(D) if the upwind State has implemented all "known" emission control measures but is still contributing significantly to nonattainment in a downwind State?

Answer:

In the Transport Rule proposal, EPA articulates an approach for addressing "significant contribution" that we believe is transferrable to future standards. This approach takes into account available reductions and their costs, informed by downwind air quality results. This approach would not require States to impose "unknown" measures. EPA would expect, however, that over time there will be improvements in technology, and future "known" control measures will likely achieve greater reductions than those that are currently "known."

Senator Lamar Alexander

1. Does the Clean Air Transport Rule (CATR) ensure that all communities will be in attainment of new EPA air quality regulations?

Answer:

EPA's analysis for the proposed Transport Rule indicated that most, but not all, communities would attain the 1997 ozone and 2006 $PM_{2.5}$ air quality standards. EPA has not yet conducted an analysis for newer air quality standards.

2. The CATR is aimed at reducing criteria pollutants from upwind states. Do you think that a full scale cap and trade, similar to the Clean Air Act Amendments of 2010 (Carper-Alexander,) can be effective at ensuring reductions from upwind states so as not to limit a downwind State's ability to meet attainment?

Answer:

The proposed Transport Rule would reduce emissions of SO2 and NOx that significantly contribute to nonattainment or interfere with maintenance in another State. The proposed Transport Rule includes assurance provisions to ensure that each individual State's emission do not exceed specified levels. An unrestricted cap and trade program, such as that included in the Clean Air Act Amendments of 2010, would ensure reductions in emissions across the eastern United States. EPA believes these reductions would significantly assist downwind State's efforts to achieve attainment.

3. Should the CATR be the sole tool used by states to ensure that communities meet attainment?

Answer:

The basis for the Transport Rule is the Clean Air Act's "good neighbor provision" in section 110(a)(2)(D)(i). This provision of the Act does not require states to eliminate all emissions that affect downwind air quality or shift sole responsibility for attaining the air quality standards to the upwind states. Instead, the "good neighbor" provision requires each upwind state to submit a SIP to prohibit those emissions that significantly contribute to nonattainment or maintenance downwind.

4. Since the Clean Air Transport Rule does not use the same allowances that were awarded under CAIR, can utilities use banked CAIR allowances to meet emissions reduction demands until the CATR is implemented?

Answer:

CAIR allowances are permitted to be used to meet compliance obligations under the Clean Air Interstate Rule cap and trade programs. Once the Transport Rule is promulgated, the CAIR programs will be replaced by the Transport Rule. New allowances will be allocated to address obligations under the Transport Rule. Note however that in the proposed Transport Rule EPA explicitly requested comment on possible approaches for handling banked pre-2012 CAIR allowances in the Transport Rule NOx programs.

5. Given the amount of banked CAIR allowances, and the utilities' ability to use those allowances to meet emission reductions levels, do you anticipate that real SO2 and NOx emissions will increase until CATR is implemented?

Answer:

EPA regularly posts updates of quarterly sulfur dioxide (SO2) and nitrogen oxides (NOX) emissions data from coal-fired power plants subject to the Acid Rain Program to make it easy for the public to track changes in emissions from these sources. Since the D.C. Circuit Court decision remanding the Clean Air Interstate Rule (CAIR) in late 2008, allowance prices of SO2 have been relatively low. This has raised concerns that coal-fired units could "backslide" on emission reductions. For example, units could burn dirtier fuels, operate scrubbers at reduced efficiency, or even bypass scrubbers altogether, relying instead on banked allowances. EPA is tracking SO2 and NOX emissions closely each quarter to evaluate further progress and assess whether backsliding may be occurring and, if so, where it may be taking place. EPA is adding new data to our website (http://www.epa.gov/airmarkets/quarterlytracking.html) on a quarterly basis as it becomes available. The data show that while a few facilities are emitting more SO2 and /or NOX or emitting SO2 and/or NOX at a greater rate in 2010 than in 2008, overall emissions are still declining.

In the first half of 2010, as compared to the first half of 2008, SO2 emissions decreased by 36%.

- 281 coal facilities decreased SO2 emissions (38 by more than 10 thousand tons)
- 125 increased SO2 emissions (two by more than 10 thousand tons).

In the first half of 2010, as compared to the first half of 2008, NOX emissions decreased by 37%.

- 338 coal facilities decreased NOX emissions (7 by more than 10 thousand tons)
- 70 increased NOx emissions (none by more than 10 thousand tons).

6. Under the CATR, intrastate trading of emission allowances is allowed, but only limited interstate trading is allowed. Has the EPA conducted an analysis showing the potential increases or decreases in electricity rates for each state?

For the national average, retail electricity rates are:

	Base Case	Limited Interstate Trading	Intrastate Trading Only
National 2014 average retail rate (cents/KWh)	8.6	8.7	8.7

EPA has not conducted an analysis at the state level.

7. How many power plant retirements will be the result of this rule?

Answer:

EPA has conducted analyses showing power plant retirements that would be expected to occur if the Transport Rule were finalized as proposed. These analyses show the following retirements under the preferred limited interstate trading remedy option:

- Total plant retirements under the preferred option are projected to be approximately 0.6 GW greater than the TR Base Case retirements.
- For coal plants, the preferred option is projected to result in an additional 1.2 GW of coal steam retirements by 2014. (v.3.02).

		Base Case	Limited Interstate Trading	Intrastate Trading Only	Direct Controls
RETIREMENTS / REPOWERINGS (GW)		2014	2014	2014	2014
CC Retirements		3.4	2.6	2.5	2.7
CT Retirements		2.9	3.3	3.3	3.4
Coal Retirements		1.8	3.0	3.4	2.2
O/G Retirements		31.6	31.4	31.4	31.3
Total		39.6	40.2	40.6	39.6

a. Would there be fewer coal plant retirements or power plant fuel switching if interstate trading was allowed?

Answer:

- EPA's analysis projects that coal retirements/repowering under the limited interstate trading option would be about 0.4 GW fewer than the coal retirements/repowering under the intrastate trading option by 2014.
- EPA's analysis projects that coal retirements under an unlimited interstate trading program would be 0.7 GW fewer than under the limited interstate trading option.

Base Case coal retirement (2014)	1.8 GW
Unlimited trading coal retirement (2014)	2.3 GW
Limited Interstate trading coal retirement (2014)	3.0 GW
Intrastate trading only (2014)	3.4 GW

8. Has the EPA conducted analysis on electrical reliability after the implementation of this rule? If so, what was the outcome of that analysis?

Answer:

EPA believes that given the flexibility provisions in the Transport Rule and the number of control installations that EPA projects (which are significantly fewer than were installed in the recent past), there should not be any reliability problems. Excess natural gas capacity, coupled with low gas prices, should also help mitigate any concerns. Recent analysis done by MJ Bradley suggests that even significantly more coal retirements than are projected under this rule would not cause reliability concerns.

9. Given the limited ability for interstate trading doesn't CATR make certain states more susceptible to higher electricity prices based on their electrical generation?

Answer:

EPA's modeling projects very little impact. Generally, electricity prices are projected to increase less than 2 percent.

a. Has EPA considered this possibility in its analysis or done a state by state assumption on electricity rates or allowance costs?

Answer:

The IPM analysis conveys in which States the budgets and variability limits are expected to be binding, and the corresponding constraint shadow price (allowance price).

While the TR is a regional trading program with a single allowance price for each pollutant and region, it is true that it may be more difficult for some states than others to achieve their state budget with variability limits.

10. Are states with coal dependent electricity portfolios more susceptible to reliability concerns or price spikes as a result of the CATR?

Answer:

EPA believes that it has designed the Transport Rule in a way that will not lead to any significant local reliability problems or price spikes. First, the limited trading provisions were designed to address this concern; second, since electricity transmission is not limited by state borders, the nature of the electricity system itself should mitigate any such concerns. EPA modeling projects less than 2 percent increase in electricity prices.

11. How does regulation or legislation limiting sulfur, nitrogen, and mercury emissions from fossil-fuel power plants affect the construction of new nuclear power plants?

Answer:

The regulation of emissions from fossil-fuel-fired power plants has very little impact on the construction of new nuclear power plants.

12. When EPA issued CAIR in 2005, it estimated that there would be 147 gigawatts of scrubbing capacity installed by 2010. What is the status of installation of scrubbing capacity today?

Answer:

By combining information in the NEEDS v.4.10 database and the planned updates published on September 1 with the recent NODA, EPA calculates approximately 181 GW of scrubbers on non-fluidized bed coal steam by the end of 2010, and 194 GW by 2012.

13. Is cap-and-trade less costly for consumers than plant-by-plant limits?

Answer:

Generally, the flexibility that cap and trade affords covered units in meeting emission reduction obligations allows for economic operations that may not be achieved with a system that imposes strict rate limits on a plant by plant basis. A large body of evidence shows that cap and trade is more cost effective for sources and consumers than other regulatory approaches.

14. Since the CATR does not recognize banked allowances, do you think this leaves EPA open to litigation under a takings clause?

Answer:

The Transport Rule has not yet been finalized and in the proposed Transport Rule, EPA explicitly requested comment on issues related to the potential use of banked allowances in the Transport Rule trading programs. Any final decision that banked allowances may not be used in the Transport Rule trading programs, however, would not give rise to a takings claim under the U.S. Constitution for several reasons. First, the statutory and/or regulatory provisions under which the Acid Rain Program and CAIR trading program allowances were created and distributed expressly state that each such allowance "does not constitute a property right." See 42 U.S.C. 7651b(f) and 40 CFR 72.9(c)(7) (for Acid Rain Program allowances); and 40 CFR 96.106(c)(6), 96.206(c)(6), 96.306(c)(6), 97.106(c)(6), 97.206(c)(6), and 97.306(c)(6) (for CAIR NOX, SO2, and NOX Ozone Season allowances). In addition, regardless of whether EPA allows the use of banked allowances in the Transport Rule trading programs, sources may continue to use banked Title IV SO2 allowances for compliance with the requirements of Title IV of the Clean Air Act.

a. Would litigation act as a delay for utilities having to meet these new reductions?

Answer: No. EPA does not believe any litigation on this issue would delay implementation of emission reduction requirements in the Transport Rule.

8-hour Ground-level Ozone Concentrations

Based on Monitored Air Quality from 2007 - 2009
Includes only Counties with Monitors

	Does not violate proposed range
	Violates 0.060 parts per million
	Violates 0.065 parts per million
	Violates 0.070 parts per million

State	County	2007 - 2009 Concentrations 3-year average
Alabama	Baldwin	0.073
Alabama	Colbert	0.068
Alabama	Elmore	0.068
Alabama	Etowah	0.067
Alabama	Houston	0.065
Alabama	Jefferson	0.08
Alabama	Madison	0.074
Alabama	Mobile	0.071
Alabama	Montgomery	0.071
Alabama	Morgan	0.07
Alabama	Russell	0.07
Alabama	Shelby	0.083
Alabama	Sumter	0.061
Alabama	Tuscaloosa	0.068
Alaska	Denali	0.058
Arizona	Cochise	0.067
Arizona	Coconino	0.068
Arizona	Gila	0.075
Arizona	La Paz	0.073
Arizona	Maricopa	0.077
Arizona	Navajo	0.068
Arizona	Pima	0.073
Arizona	Pinal	0.075
Arkansas	Crittenden	0.079
Arkansas	Newton	0.068
Arkansas	Polk	0.072
Arkansas	Pulaski	0.074
Arkansas	Washington	0.064
California	Alameda	0.073
California	Amador	0.081
California	Butte	0.082
California	Calaveras	0.083
California	Colusa	0.068
California	Contra Costa	0.073
California	El Dorado	0.094
California	Fresno	0.100
California	Glenn	0.068
California	Humboldt	0.047

California	Imperial	0.083
California	Inyo	0.077
California	Kern	0.105
California	Kings	0.092
California	Lake	0.062
California	Los Angeles	0.105
California	Madera	0.084
California	Marin	0.053
California	Mariposa	0.086
California	Mendocino	0.063
California	Merced	0.091
California	Monterey	0.069
California	Napa	0.062
California	Nevada	0.067
California	Orange	0.086
California	Placer	0.089
California	Riverside	0.105
California	Sacramento	0.1
California	San Benito	0.077
California	San Bernardino	0.115
California	San Diego	0.08
California	San Francisco	0.048
California	San Joaquin	0.083
California	San Luis Obispo	0.085
California	San Mateo	0.056
California	Santa Barbara	0.077
California	Santa Clara	0.073
California	Santa Cruz	0.056
California	Shasta	0.077
California	Siskiyou	0.061
California	Solano	0.075
California	Sonoma	0.052
California	Stanislaus	0.088
California	Sutter	0.078
California	Tehama	0.082
California	Tulare	0.103
California	Tuolumne	0.085
California	Ventura	0.065
California	Yolo	0.076
Colorado	Adams	0.075
Colorado	Arapahoe	0.065
Colorado	Boulder	0.078
Colorado	Denver	0.07
Colorado	Douglas	0.078
Colorado	El Paso	0.069
Colorado	Jefferson	0.083
Colorado	La Plata	0.07
Colorado	Larimer	0.078
Colorado	Montezuma	0.069
Colorado	Weld	0.071
Connecticut	Fairfield	0.084
Connecticut	Hartford	0.081

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Connecticut	Litchfield	0.078
Connecticut	Middlesex	0.082
Connecticut	New Haven	0.081
Connecticut	New London	0.083
Connecticut	Tolland	0.082
Delaware	Kent	0.076
Delaware	New Castle	0.079
Delaware	Sussex	0.076
District Of Columb	District of Columbi	0.081
Florida	Alachua	0.058
Florida	Baker	0.054
Florida	Bay	0.072
Florida	Brevard	0.066
Florida	Broward	0.063
Florida	Collier	0.057
Florida	Columbia	0.065
Florida	Duval	0.071
Florida	Escambia	0.076
Florida	Highlands	0.065
Florida	Hillsborough	0.079
Florida	Holmes	0.066
Florida	Lake	0.071
Florida	Lee	0.066
Florida	Leon	0.068
Florida	Manatee	0.07
Florida	Marion	0.067
Florida	Miami-Dade	0.062
Florida	Orange	0.071
Florida	Osceola	0.068
Florida	Palm Beach	0.065
Florida	Pasco	0.072
Florida	Pinellas	0.068
Florida	Polk	0.071
Florida	Santa Rosa	0.078
Florida	Sarasota	0.075
Florida	Seminole	0.066
Florida	St. Lucie	0.063
Florida	Volusia	0.063
Florida	Wakulla	0.066
Georgia	Bibb	0.076
Georgia	Chatham	0.065
Georgia	Chattooga	0.071
Georgia	Clarke	0.075
Georgia	Cobb	0.08
Georgia	Columbia	0.071
Georgia	Coweta	0.077
Georgia	Dawson	0.073
Georgia	DeKalb	0.087
Georgia	Douglas	0.079
Georgia	Fulton	0.086
Georgia	Glynn	0.062
Georgia	Gwinnett	0.081

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Georgia	Henry	[illegible]
Georgia	Murray	0.076
Georgia	Muscogee	0.074
Georgia	Paulding	0.074
Georgia	Richmond	0.074
Georgia	Rockdale	[illegible]
Georgia	Sumter	0.068
Hawaii	Honolulu	0.041
Idaho	**Ada**	**0.071**
Idaho	Butte	0.064
Idaho	Kootenai	0.06
Illinois	Adams	0.067
Illinois	Champaign	0.065
Illinois	Clark	0.068
Illinois	Cook	0.074
Illinois	DuPage	0.063
Illinois	Effingham	0.069
Illinois	Hamilton	0.069
Illinois	Jersey	0.071
Illinois	Kane	0.068
Illinois	Lake	0.076
Illinois	Macon	0.07
Illinois	Macoupin	0.068
Illinois	Madison	0.077
Illinois	McHenry	0.068
Illinois	McLean	0.071
Illinois	Peoria	0.072
Illinois	Randolph	0.068
Illinois	Rock Island	0.062
Illinois	Saint Clair	0.07
Illinois	Sangamon	0.064
Illinois	Will	0.065
Illinois	Winnebago	0.067
Indiana	Allen	0.071
Indiana	Boone	0.075
Indiana	Carroll	0.069
Indiana	Clark	0.077
Indiana	Delaware	0.07
Indiana	Elkhart	0.07
Indiana	Floyd	0.073
Indiana	Greene	0.076
Indiana	Hamilton	0.075
Indiana	Hancock	0.074
Indiana	Hendricks	0.072
Indiana	Huntington	0.067
Indiana	Jackson	0.07
Indiana	Johnson	0.073
Indiana	Lake	0.071
Indiana	LaPorte	0.069
Indiana	Madison	0.069
Indiana	Marion	0.077
Indiana	Morgan	0.074

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Indiana	Perry	0.073
Indiana	Porter	0.073
Indiana	Posey	0.072
Indiana	Shelby	0.076
Indiana	St. Joseph	0.071
Indiana	Vanderburgh	0.075
Indiana	Vigo	0.067
Indiana	Warrick	0.072
Iowa	Bremer	0.064
Iowa	Clinton	0.067
Iowa	Harrison	0.064
Iowa	Linn	0.066
Iowa	Montgomery	0.064
Iowa	Palo Alto	0.059
Iowa	Polk	0.061
Iowa	Scott	0.067
Iowa	Story	0.063
Iowa	Van Buren	0.064
Iowa	Warren	0.063
Kansas	Johnson	0.065
Kansas	Leavenworth	0.068
Kansas	Linn	0.065
Kansas	Sedgwick	0.066
Kansas	Shawnee	0.066
Kansas	Sumner	0.07
Kansas	Trego	0.068
Kansas	Wyandotte	0.068
Kentucky	Bell	0.067
Kentucky	Boone	0.069
Kentucky	Boyd	0.07
Kentucky	Bullitt	0.07
Kentucky	Campbell	0.075
Kentucky	Carter	0.069
Kentucky	Christian	0.076
Kentucky	Daviess	0.075
Kentucky	Edmonson	0.073
Kentucky	Fayette	0.07
Kentucky	Greenup	0.072
Kentucky	Hancock	0.074
Kentucky	Hardin	0.074
Kentucky	Henderson	0.079
Kentucky	Jefferson	0.076
Kentucky	Jessamine	0.071
Kentucky	Kenton	0.077
Kentucky	Livingston	0.07
Kentucky	McCracken	0.073
Kentucky	Oldham	0.074
Kentucky	Perry	0.07
Kentucky	Pike	0.071
Kentucky	Pulaski	0.069
Kentucky	Simpson	0.073
Kentucky	Trigg	0.074

Kentucky	Warren	0.069
Louisiana	Ascension	0.079
Louisiana	Bossier	0.072
Louisiana	Caddo	0.071
Louisiana	Calcasieu	0.075
Louisiana	East Baton Rouge	0.08
Louisiana	Iberville	0.076
Louisiana	Jefferson	0.077
Louisiana	Lafayette	0.073
Louisiana	Lafourche	0.072
Louisiana	Livingston	0.079
Louisiana	Ouachita	0.063
Louisiana	Pointe Coupee	0.077
Louisiana	St Bernard	0.07
Louisiana	St Charles	0.071
Louisiana	St James	0.071
Louisiana	St John the Baptist	0.077
Louisiana	West Baton Rouge	0.073
Maine	Androscoggin	0.073
Maine	Aroostook	0.055
Maine	Cumberland	0.074
Maine	Hancock	0.078
Maine	Kennebec	0.071
Maine	Knox	0.071
Maine	Oxford	0.063
Maine	Penobscot	0.064
Maine	Washington	0.065
Maine	York	0.074
Maryland	Anne Arundel	0.08
Maryland	Baltimore	0.078
Maryland	Baltimore (City)	0.067
Maryland	Calvert	0.075
Maryland	Carroll	0.078
Maryland	Cecil	0.084
Maryland	Charles	0.079
Maryland	Frederick	0.077
Maryland	Garrett	0.071
Maryland	Harford	0.087
Maryland	Kent	0.079
Maryland	Montgomery	0.075
Maryland	Prince Georges	0.078
Maryland	Washington	0.074
Massachusetts	Barnstable	0.076
Massachusetts	Berkshire	0.073
Massachusetts	Bristol	0.075
Massachusetts	Dukes	0.077
Massachusetts	Essex	0.08
Massachusetts	Hampden	0.084
Massachusetts	Hampshire	0.081
Massachusetts	Middlesex	0.077
Massachusetts	Norfolk	0.078
Massachusetts	Suffolk	0.074

Massachusetts	Worcester	0.062
Michigan	Allegan	0.081
Michigan	Benzie	0.072
Michigan	Berrien	0.075
Michigan	Cass	0.075
Michigan	Clinton	0.071
Michigan	Genesee	0.074
Michigan	Huron	0.072
Michigan	Ingham	0.073
Michigan	Kalamazoo	0.074
Michigan	Kent	0.075
Michigan	Lenawee	0.073
Michigan	Macomb	0.08
Michigan	Manistee	0.072
Michigan	Mason	0.072
Michigan	Missaukee	0.069
Michigan	Muskegon	0.077
Michigan	Oakland	0.078
Michigan	Ottawa	0.075
Michigan	Schoolcraft	0.071
Michigan	St. Clair	0.076
Michigan	Washtenaw	0.07
Michigan	Wayne	0.08
Minnesota	Anoka	0.065
Minnesota	Crow Wing	0.063
Minnesota	Goodhue	0.065
Minnesota	Lyon	0.062
Minnesota	Mille Lacs	0.061
Minnesota	Olmsted	0.061
Minnesota	Saint Louis	0.061
Minnesota	Scott	0.063
Minnesota	Washington	0.063
Minnesota	Wright	0.065
Mississippi	Adams	0.068
Mississippi	Bolivar	0.069
Mississippi	DeSoto	0.078
Mississippi	Harrison	0.079
Mississippi	Hinds	0.067
Mississippi	Jackson	0.076
Mississippi	Lauderdale	0.065
Mississippi	Lee	0.069
Missouri	Cass	0.067
Missouri	Cedar	0.068
Missouri	Clay	0.077
Missouri	Clinton	0.076
Missouri	Greene	0.07
Missouri	Lincoln	0.075
Missouri	Monroe	0.067
Missouri	Perry	0.074
Missouri	Saint Charles	0.079
Missouri	Saint Louis	0.078
Missouri	Sainte Genevieve	0.076

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Missouri	St. Louis City	0.075
Montana	Flathead	0.055
Nebraska	Douglas	0.06
Nebraska	Lancaster	0.053
Nevada	Churchill	0.065
Nevada	Clark	0.076
Nevada	Lyon	0.063
Nevada	Washoe	0.072
Nevada	White Pine	0.072
New Hampshire	Belknap	0.063
New Hampshire	Cheshire	0.065
New Hampshire	Coos	0.075
New Hampshire	Grafton	0.068
New Hampshire	Hillsborough	0.076
New Hampshire	Merrimack	0.065
New Hampshire	Rockingham	0.075
New Jersey	Atlantic	0.074
New Jersey	Bergen	0.061
New Jersey	Camden	0.081
New Jersey	Cumberland	0.078
New Jersey	Gloucester	0.083
New Jersey	Hudson	0.081
New Jersey	Hunterdon	0.081
New Jersey	Mercer	0.081
New Jersey	Middlesex	0.08
New Jersey	Monmouth	0.081
New Jersey	Morris	0.079
New Jersey	Ocean	0.081
New Jersey	Passaic	0.077
New Mexico	Bernalillo	0.07
New Mexico	Dona Ana	0.072
New Mexico	Eddy	0.066
New Mexico	Grant	0.061
New Mexico	Lea	0.063
New Mexico	Luna	0.059
New Mexico	San Juan	0.07
New Mexico	Sandoval	0.066
New Mexico	Santa Fe	0.063
New York	Albany	0.072
New York	Bronx	0.072
New York	Chautauqua	0.079
New York	Chemung	0.069
New York	Dutchess	0.076
New York	Erie	0.075
New York	Essex	0.079
New York	Franklin	0.064
New York	Hamilton	0.07
New York	Herkimer	0.07
New York	Jefferson	0.074
New York	Madison	0.072
New York	Monroe	0.073
New York	New York	0.076

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New York	Niagara	0.073
New York	Oneida	0.065
New York	Onondaga	0.071
New York	Orange	0.075
New York	Oswego	0.071
New York	Putnam	0.078
New York	Queens	0.074
New York	Rensselaer	0.074
New York	Richmond	0.075
New York	Saratoga	0.076
New York	Schenectady	0.067
New York	Steuben	0.069
New York	Suffolk	0.085
New York	Ulster	0.069
New York	Wayne	0.071
New York	Westchester	0.084
North Carolina	Alexander	0.073
North Carolina	Avery	0.065
North Carolina	Buncombe	0.069
North Carolina	Caldwell	0.071
North Carolina	Caswell	0.076
North Carolina	Chatham	0.07
North Carolina	Cumberland	0.074
North Carolina	Davie	0.076
North Carolina	Durham	0.074
North Carolina	Edgecombe	0.074
North Carolina	Forsyth	0.076
North Carolina	Franklin	0.073
North Carolina	Graham	0.079
North Carolina	Granville	0.077
North Carolina	Guilford	0.08
North Carolina	Haywood	0.074
North Carolina	Johnston	0.073
North Carolina	Lenoir	0.072
North Carolina	Lincoln	0.078
North Carolina	Martin	0.071
North Carolina	Mecklenburg	0.087
North Carolina	New Hanover	0.065
North Carolina	Person	0.074
North Carolina	Rockingham	0.078
North Carolina	Rowan	0.084
North Carolina	Swain	0.064
North Carolina	Union	0.078
North Carolina	Wake	0.077
North Carolina	Yancey	0.074
North Dakota	Billings	0.06
North Dakota	Burke	0.059
North Dakota	Burleigh	0.057
North Dakota	Cass	0.056
North Dakota	Dunn	0.057
North Dakota	McKenzie	0.061
North Dakota	Mercer	0.058

North Dakota	Oliver	0.069
Ohio	Allen	0.075
Ohio	Ashtabula	0.081
Ohio	Athens	0.072
Ohio	Butler	0.082
Ohio	Clark	0.075
Ohio	Clermont	0.079
Ohio	Clinton	0.076
Ohio	Cuyahoga	0.077
Ohio	Delaware	0.079
Ohio	Franklin	0.081
Ohio	Geauga	0.073
Ohio	Greene	0.074
Ohio	Hamilton	0.082
Ohio	Jefferson	0.072
Ohio	Knox	0.074
Ohio	Lake	0.075
Ohio	Lawrence	0.074
Ohio	Licking	0.074
Ohio	Lorain	0.072
Ohio	Lucas	0.074
Ohio	Madison	0.074
Ohio	Mahoning	0.075
Ohio	Medina	0.07
Ohio	Miami	0.075
Ohio	Montgomery	0.079
Ohio	Portage	0.072
Ohio	Preble	0.07
Ohio	Stark	0.076
Ohio	Summit	0.08
Ohio	Trumbull	0.077
Ohio	Warren	0.082
Ohio	Washington	0.077
Ohio	Wood	0.074
Oklahoma	Adair	0.058
Oklahoma	Canadian	0.071
Oklahoma	Cherokee	0.055
Oklahoma	Cleveland	0.052
Oklahoma	Comanche	0.071
Oklahoma	Creek	0.071
Oklahoma	Dewey	0.057
Oklahoma	Kay	0.07
Oklahoma	Mayes	0.052
Oklahoma	McClain	0.054
Oklahoma	Oklahoma	0.075
Oklahoma	Ottawa	0.057
Oklahoma	Pittsburg	0.055
Oklahoma	Sequoyah	0.057
Oklahoma	Tulsa	0.075
Oregon	Clackamas	0.064
Oregon	Columbia	0.058
Oregon	Jackson	0.067

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Oregon	Lane	0.062
Oregon	Marion	0.065
Oregon	Multnomah	0.059
Oregon	Umatilla	0.064
Pennsylvania	Adams	0.074
Pennsylvania	Allegheny	0.083
Pennsylvania	Armstrong	0.077
Pennsylvania	Beaver	0.073
Pennsylvania	Berks	0.079
Pennsylvania	Blair	0.07
Pennsylvania	Bucks	0.085
Pennsylvania	Cambria	0.068
Pennsylvania	Centre	0.071
Pennsylvania	Chester	0.077
Pennsylvania	Clearfield	0.072
Pennsylvania	Dauphin	0.076
Pennsylvania	Delaware	0.077
Pennsylvania	Erie	0.075
Pennsylvania	Franklin	0.07
Pennsylvania	Greene	0.072
Pennsylvania	Indiana	0.074
Pennsylvania	Lackawanna	0.073
Pennsylvania	Lancaster	0.077
Pennsylvania	Lawrence	0.069
Pennsylvania	Lehigh	0.077
Pennsylvania	Luzerne	0.069
Pennsylvania	Lycoming	0.074
Pennsylvania	Mercer	0.071
Pennsylvania	Monroe	0.068
Pennsylvania	Montgomery	0.079
Pennsylvania	Northampton	0.073
Pennsylvania	Perry	0.072
Pennsylvania	Philadelphia	0.086
Pennsylvania	Tioga	0.07
Pennsylvania	Washington	0.072
Pennsylvania	Westmoreland	0.072
Pennsylvania	York	0.078
Puerto Rico	Catano	0.037
Rhode Island	Kent	0.077
Rhode Island	Providence	0.077
Rhode Island	Washington	0.077
South Carolina	Abbeville	0.073
South Carolina	Aiken	0.076
South Carolina	Berkeley	0.061
South Carolina	Charleston	0.066
South Carolina	Cherokee	0.068
South Carolina	Chesterfield	0.07
South Carolina	Colleton	0.067
South Carolina	Darlington	0.071
South Carolina	Edgefield	0.069
South Carolina	Oconee	0.073
South Carolina	Pickens	0.076

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South Carolina	Richland	0.076
South Carolina	Spartanburg	0.078
South Carolina	York	0.072
South Dakota	Custer	0.063
South Dakota	Meade	0.057
Tennessee	Anderson	0.073
Tennessee	Blount	0.08
Tennessee	Davidson	0.07
Tennessee	Hamilton	0.079
Tennessee	Jefferson	0.076
Tennessee	Knox	0.082
Tennessee	Loudon	0.077
Tennessee	Meigs	0.074
Tennessee	Rutherford	0.074
Tennessee	Sevier	0.073
Tennessee	Shelby	0.078
Tennessee	Sullivan	0.077
Tennessee	Sumner	0.078
Tennessee	Williamson	0.072
Tennessee	Wilson	0.076
Texas	Bexar	0.075
Texas	Brazoria	0.064
Texas	Brewster	0.056
Texas	Cameron	0.062
Texas	Collin	0.079
Texas	Dallas	0.081
Texas	Denton	0.085
Texas	El Paso	0.075
Texas	Ellis	0.073
Texas	Galveston	0.077
Texas	Gregg	0.075
Texas	Harris	0.084
Texas	Harrison	0.066
Texas	Hays	0.065
Texas	Hidalgo	0.058
Texas	Hood	0.077
Texas	Hunt	0.069
Texas	Jefferson	0.077
Texas	Johnson	0.083
Texas	Kaufman	0.07
Texas	McLennan	0.072
Texas	Montgomery	0.071
Texas	Nueces	0.07
Texas	Orange	0.07
Texas	Parker	0.082
Texas	Rockwall	0.079
Texas	Smith	0.075
Texas	Tarrant	0.087
Texas	Travis	0.075
Texas	Victoria	0.065
Texas	Webb	0.055
Utah	Box Elder	0.072

Utah	Cache	0.067
Utah	Davis	0.077
Utah	Salt Lake	0.078
Utah	San Juan	0.07
Utah	Tooele	0.072
Utah	Utah	0.073
Utah	Washington	0.07
Utah	Weber	0.076
Vermont	Bennington	0.073
Vermont	Chittenden	0.059
Virginia	Alexandria City	0.075
Virginia	Arlington	0.08
Virginia	Caroline	0.075
Virginia	Charles	0.077
Virginia	Chesterfield	0.074
Virginia	Fairfax	0.081
Virginia	Fauquier	0.067
Virginia	Frederick	0.066
Virginia	Hanover	0.073
Virginia	Henrico	0.075
Virginia	Loudoun	0.073
Virginia	Madison	0.073
Virginia	Page	0.067
Virginia	Prince William	0.073
Virginia	Roanoke	0.07
Virginia	Rockbridge	0.064
Virginia	Rockingham	0.067
Virginia	Stafford	0.073
Virginia	Suffolk City	0.073
Virginia	Wythe	0.068
Washington	Clallam	0.055
Washington	Clark	0.061
Washington	**King**	**0.073**
Washington	Pierce	0.065
Washington	Spokane	0.06
Washington	Thurston	0.058
West Virginia	Berkeley	0.07
West Virginia	Cabell	0.073
West Virginia	Greenbrier	0.062
West Virginia	Hancock	0.074
West Virginia	Kanawha	0.073
West Virginia	Monongalia	0.072
West Virginia	Ohio	0.074
West Virginia	Wood	0.072
Wisconsin	Ashland	0.06
Wisconsin	Brown	0.07
Wisconsin	Columbia	0.068
Wisconsin	Dane	0.066
Wisconsin	Dodge	0.068
Wisconsin	Door	0.078
Wisconsin	Florence	0.063
Wisconsin	Fond du Lac	0.067

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Wisconsin	Forest	[illegible]
Wisconsin	Jefferson	0.07
Wisconsin	Kenosha	0.076
Wisconsin	Kewaunee	0.074
Wisconsin	Manitowoc	[illegible]
Wisconsin	Marathon	0.065
Wisconsin	Milwaukee	0.078
Wisconsin	Oneida	0.065
Wisconsin	Outagamie	0.067
Wisconsin	Ozaukee	0.074
Wisconsin	Racine	0.071
Wisconsin	Rock	[illegible]
Wisconsin	Sauk	0.064
Wisconsin	Sheboygan	0.079
Wisconsin	St. Croix	[illegible]
Wisconsin	Vernon	[illegible]
Wisconsin	Vilas	0.065
Wisconsin	Walworth	[illegible]
Wisconsin	Washington	0.065
Wisconsin	Waukesha	0.064
Wyoming	Campbell	[illegible]
Wyoming	Fremont	0.072
Wyoming	Sublette	0.078
Wyoming	Sweetwater	[illegible]
Wyoming	Teton	0.064
Wyoming	Uinta	0.065

Counties Projected to Violate Primary 8-hour Ground-Level Ozone Standard in 2020

(Model projections for 2020)
(Only includes counties with monitors)

	Not projected to violate proposed range
	Projected to violate 0.060 parts per million
	Projected to violate 0.065 parts per million
	Projected to violate 0.070 parts per million

State	County
Alabama	Baldwin
Alabama	Clay
Alabama	Elmore
Alabama	Etowah
Alabama	Jefferson
Alabama	Lawrence
Alabama	Madison
Alabama	Mobile
Alabama	Montgomery
Alabama	Morgan
Alabama	Shelby
Alabama	Sumter
Alabama	Tuscaloosa
Arizona	Cochise
Arizona	Coconino
Arizona	Maricopa
Arizona	Navajo
Arizona	Pima
Arizona	Pinal
Arizona	Yavapai
Arkansas	Crittenden
Arkansas	Montgomery
Arkansas	Newton
Arkansas	Pulaski
California	Alameda
California	Amador
California	Butte
California	Calaveras
California	Colusa
California	Contra Costa
California	El Dorado
California	Fresno
California	Glenn
California	Imperial
California	Inyo

California	Kern
California	Kings
California	Lake
California	Los Angeles
California	Madera
California	Marin
California	Mariposa
California	Mendocino
California	Merced
California	Monterey
California	Napa
California	Nevada
California	Orange
California	Placer
California	Riverside
California	Sacramento
California	San Benito
California	San Bernardino
California	San Diego
California	San Francisco
California	San Joaquin
California	San Luis Obispo
California	San Mateo
California	Santa Barbara
California	Santa Clara
California	Santa Cruz
California	Shasta
California	Solano
California	Sonoma
California	Stanislaus
California	Sutter
California	Tehama
California	Tulare
California	Tuolumne
California	Ventura
California	Yolo
Colorado	Adams
Colorado	Arapahoe
Colorado	Boulder
Colorado	Denver
Colorado	Douglas
Colorado	El Paso
Colorado	Jefferson
Colorado	La Plata
Colorado	Larimer
Colorado	Montezuma
Colorado	Weld
Connecticut	Fairfield
Connecticut	Hartford
Connecticut	Litchfield
Connecticut	Middlesex
Connecticut	New Haven

Connecticut	New London
Connecticut	Tolland
D.C.	Washington
Delaware	Kent
Delaware	New Castle
Delaware	Sussex
Florida	Alachua
Florida	Baker
Florida	Bay
Florida	Brevard
Florida	Broward
Florida	Collier
Florida	Columbia
Florida	Duval
Florida	Escambia
Florida	Highlands
Florida	Hillsborough
Florida	Holmes
Florida	Lake
Florida	Lee
Florida	Leon
Florida	Manatee
Florida	Marion
Florida	Miami-Dade
Florida	Orange
Florida	Osceola
Florida	Palm Beach
Florida	Pasco
Florida	Pinellas
Florida	Polk
Florida	Santa Rosa
Florida	Sarasota
Florida	Seminole
Florida	St Lucie
Florida	Volusia
Florida	Wakulla
Georgia	Bibb
Georgia	Chatham
Georgia	Cherokee
Georgia	Clarke
Georgia	Cobb
Georgia	Coweta
Georgia	Dawson
Georgia	De Kalb
Georgia	Douglas
Georgia	Fayette
Georgia	Fulton
Georgia	Glynn
Georgia	Gwinnett
Georgia	Henry
Georgia	Murray
Georgia	Muscogee

Georgia	Paulding
Georgia	Richmond
Georgia	Rockdale
Georgia	Sumter
Idaho	Ada
Idaho	Butte
Idaho	Canyon
Idaho	Elmore
Illinois	Adams
Illinois	Champaign
Illinois	Clark
Illinois	Cook
Illinois	Du Page
Illinois	Effingham
Illinois	Hamilton
Illinois	Jersey
Illinois	Kane
Illinois	Lake
Illinois	Macon
Illinois	Macoupin
Illinois	Madison
Illinois	McHenry
Illinois	McLean
Illinois	Peoria
Illinois	Randolph
Illinois	Rock Island
Illinois	Sangamon
Illinois	St Clair
Illinois	Will
Illinois	Winnebago
Indiana	Allen
Indiana	Boone
Indiana	Carroll
Indiana	Clark
Indiana	Delaware
Indiana	Elkhart
Indiana	Floyd
Indiana	Gibson
Indiana	Greene
Indiana	Hamilton
Indiana	Hancock
Indiana	Hendricks
Indiana	Huntington
Indiana	Jackson
Indiana	Johnson
Indiana	La Porte
Indiana	Lake
Indiana	Madison
Indiana	Marion
Indiana	Morgan
Indiana	Porter
Indiana	Posey

Indiana	Shelby
Indiana	St Joseph
Indiana	Vanderburgh
Indiana	Vigo
Indiana	Warrick
Iowa	Bremer
Iowa	Clinton
Iowa	Harrison
Iowa	Linn
Iowa	Montgomery
Iowa	Palo Alto
Iowa	Polk
Iowa	Scott
Iowa	Story
Iowa	Van Buren
Iowa	Warren
Kansas	Linn
Kansas	Sedgwick
Kansas	Sumner
Kansas	Trego
Kansas	Wyandotte
Kentucky	Bell
Kentucky	Boone
Kentucky	Boyd
Kentucky	Bullitt
Kentucky	Campbell
Kentucky	Carter
Kentucky	Christian
Kentucky	Daviess
Kentucky	Edmonson
Kentucky	Fayette
Kentucky	Graves
Kentucky	Greenup
Kentucky	Hancock
Kentucky	Hardin
Kentucky	Henderson
Kentucky	Jefferson
Kentucky	Jessamine
Kentucky	Kenton
Kentucky	Livingston
Kentucky	McCracken
Kentucky	McLean
Kentucky	Oldham
Kentucky	Perry
Kentucky	Pike
Kentucky	Pulaski
Kentucky	Scott
Kentucky	Simpson
Kentucky	Trigg
Kentucky	Warren
Louisiana	Ascension
Louisiana	Beauregard

Louisiana	Bossier
Louisiana	Caddo
Louisiana	Calcasieu
Louisiana	East Baton Rouge
Louisiana	Grant
Louisiana	Iberville
Louisiana	Jefferson
Louisiana	Lafayette
Louisiana	Lafourche
Louisiana	Livingston
Louisiana	Orleans
Louisiana	Ouachita
Louisiana	Pointe Coupee
Louisiana	St Bernard
Louisiana	St Charles
Louisiana	St James
Louisiana	St John The Bapti
Louisiana	St Mary
Louisiana	West Baton Rouge
Maine	Cumberland
Maine	Hancock
Maine	Kennebec
Maine	Knox
Maine	Oxford
Maine	Penobscot
Maine	Sagadahoc
Maine	York
Maryland	Anne Arundel
Maryland	Baltimore
Maryland	Carroll
Maryland	Cecil
Maryland	Charles
Maryland	Frederick
Maryland	Harford
Maryland	Kent
Maryland	Montgomery
Maryland	Prince Georges
Maryland	Washington
Massachusetts	Barnstable
Massachusetts	Berkshire
Massachusetts	Bristol
Massachusetts	Essex
Massachusetts	Hampden
Massachusetts	Hampshire
Massachusetts	Middlesex
Massachusetts	Norfolk
Massachusetts	Suffolk
Massachusetts	Worcester
Michigan	Allegan
Michigan	Benzie
Michigan	Berrien
Michigan	Cass

Michigan	Clinton
Michigan	Genesee
Michigan	Huron
Michigan	Ingham
Michigan	Kalamazoo
Michigan	Kent
Michigan	Lenawee
Michigan	Macomb
Michigan	Mason
Michigan	Missaukee
Michigan	Muskegon
Michigan	Oakland
Michigan	Ottawa
Michigan	Schoolcraft
Michigan	St Clair
Michigan	Washtenaw
Michigan	Wayne
Minnesota	St Louis
Mississippi	Adams
Mississippi	Bolivar
Mississippi	De Soto
Mississippi	Hancock
Mississippi	Harrison
Mississippi	Hinds
Mississippi	Jackson
Mississippi	Lauderdale
Mississippi	Lee
Mississippi	Madison
Mississippi	Warren
Missouri	Cass
Missouri	Cedar
Missouri	Clay
Missouri	Greene
Missouri	Jefferson
Missouri	Monroe
Missouri	Platte
Missouri	St Charles
Missouri	St Louis
Missouri	St Louis City
Missouri	Ste Genevieve
Montana	Flathead
Nebraska	Douglas
Nebraska	Lancaster
Nevada	Carson City
Nevada	Clark
Nevada	Douglas
Nevada	Washoe
Nevada	White Pine
New Hampshire	Belknap
New Hampshire	Carroll
New Hampshire	Cheshire
New Hampshire	Grafton

New Hampshire	Hillsborough
New Hampshire	Merrimack
New Hampshire	Rockingham
New Hampshire	Strafford
New Hampshire	Sullivan
New Jersey	Atlantic
New Jersey	Bergen
New Jersey	Camden
New Jersey	Cumberland
New Jersey	Essex
New Jersey	Gloucester
New Jersey	Hudson
New Jersey	Hunterdon
New Jersey	Mercer
New Jersey	Middlesex
New Jersey	Monmouth
New Jersey	Morris
New Jersey	Ocean
New Jersey	Passaic
New Mexico	Bernalillo
New Mexico	Dona Ana
New Mexico	Eddy
New Mexico	San Juan
New Mexico	Sandoval
New Mexico	Valencia
New York	Albany
New York	Bronx
New York	Chautauqua
New York	Chemung
New York	Dutchess
New York	Erie
New York	Essex
New York	Hamilton
New York	Herkimer
New York	Jefferson
New York	Madison
New York	Monroe
New York	Niagara
New York	Oneida
New York	Onondaga
New York	Orange
New York	Oswego
New York	Putnam
New York	Queens
New York	Rensselaer
New York	Richmond
New York	Saratoga
New York	Schenectady
New York	Suffolk
New York	Ulster
New York	Wayne
New York	Westchester

North Carolina	Alexander
North Carolina	Avery
North Carolina	Buncombe
North Carolina	Caldwell
North Carolina	Caswell
North Carolina	Chatham
North Carolina	Cumberland
North Carolina	Davie
North Carolina	Duplin
North Carolina	Durham
North Carolina	Edgecombe
North Carolina	Forsyth
North Carolina	Franklin
North Carolina	Granville
North Carolina	Guilford
North Carolina	Haywood
North Carolina	Jackson
North Carolina	Johnston
North Carolina	Lenoir
North Carolina	Lincoln
North Carolina	Martin
North Carolina	**Mecklenburg**
North Carolina	New Hanover
North Carolina	Northampton
North Carolina	Person
North Carolina	Pitt
North Carolina	Randolph
North Carolina	Rockingham
North Carolina	Rowan
North Carolina	Swain
North Carolina	Union
North Carolina	Wake
North Carolina	Yancey
North Dakota	Billings
North Dakota	Cass
North Dakota	Dunn
North Dakota	McKenzie
North Dakota	Mercer
North Dakota	Oliver
Ohio	Allen
Ohio	**Ashtabula**
Ohio	Butler
Ohio	Clark
Ohio	Clermont
Ohio	Clinton
Ohio	Cuyahoga
Ohio	Delaware
Ohio	Franklin
Ohio	**Geauga**
Ohio	Greene
Ohio	Hamilton
Ohio	Jefferson

Ohio	Knox
Ohio	Lake
Ohio	Lawrence
Ohio	Licking
Ohio	Lorain
Ohio	Lucas
Ohio	Madison
Ohio	Mahoning
Ohio	Medina
Ohio	Miami
Ohio	Montgomery
Ohio	Portage
Ohio	Preble
Ohio	Stark
Ohio	Summit
Ohio	Trumbull
Ohio	Warren
Ohio	Washington
Ohio	Wood
Oklahoma	Canadian
Oklahoma	Cleveland
Oklahoma	Comanche
Oklahoma	Dewey
Oklahoma	Kay
Oklahoma	Mc Clain
Oklahoma	Oklahoma
Oklahoma	Ottawa
Oklahoma	Pittsburg
Oklahoma	Tulsa
Oregon	Clackamas
Oregon	Columbia
Oregon	Jackson
Oregon	Lane
Oregon	Marion
Pennsylvania	Adams
Pennsylvania	Allegheny
Pennsylvania	Armstrong
Pennsylvania	Beaver
Pennsylvania	Berks
Pennsylvania	Blair
Pennsylvania	Bucks
Pennsylvania	Cambria
Pennsylvania	Centre
Pennsylvania	Chester
Pennsylvania	Clearfield
Pennsylvania	Dauphin
Pennsylvania	Delaware
Pennsylvania	Erie
Pennsylvania	Franklin
Pennsylvania	Greene
Pennsylvania	Lackawanna
Pennsylvania	Lancaster

Pennsylvania	Lawrence
Pennsylvania	Lehigh
Pennsylvania	Luzerne
Pennsylvania	Lycoming
Pennsylvania	Mercer
Pennsylvania	Montgomery
Pennsylvania	Northampton
Pennsylvania	Perry
Pennsylvania	Philadelphia
Pennsylvania	Tioga
Pennsylvania	Washington
Pennsylvania	Westmoreland
Pennsylvania	York
Rhode Island	Kent
Rhode Island	Providence
Rhode Island	Washington
South Carolina	Abbeville
South Carolina	Aiken
South Carolina	Anderson
South Carolina	Barnwell
South Carolina	Berkeley
South Carolina	Charleston
South Carolina	Cherokee
South Carolina	Chester
South Carolina	Chesterfield
South Carolina	Colleton
South Carolina	Darlington
South Carolina	Edgefield
South Carolina	Oconee
South Carolina	Pickens
South Carolina	Richland
South Carolina	Spartanburg
South Carolina	Union
South Carolina	Williamsburg
South Carolina	York
South Dakota	Pennington
Tennessee	Anderson
Tennessee	Blount
Tennessee	Davidson
Tennessee	Hamilton
Tennessee	Haywood
Tennessee	Jefferson
Tennessee	Knox
Tennessee	Lawrence
Tennessee	Meigs
Tennessee	Putnam
Tennessee	Rutherford
Tennessee	Sevier
Tennessee	Shelby
Tennessee	Sullivan
Tennessee	Sumner
Tennessee	Williamson

Tennessee	Wilson
Texas	Bexar
Texas	Brazoria
Texas	Brewster
Texas	Cameron
Texas	Collin
Texas	Dallas
Texas	Denton
Texas	El Paso
Texas	Ellis
Texas	Galveston
Texas	Gregg
Texas	Harris
Texas	Harrison
Texas	Hidalgo
Texas	Hood
Texas	Jefferson
Texas	Johnson
Texas	Kaufman
Texas	Montgomery
Texas	Nueces
Texas	Orange
Texas	Parker
Texas	Rockwall
Texas	Smith
Texas	Tarrant
Texas	Travis
Texas	Victoria
Texas	Webb
Utah	Box Elder
Utah	Cache
Utah	Davis
Utah	Salt Lake
Utah	San Juan
Utah	Utah
Utah	Weber
Vermont	Bennington
Vermont	Chittenden
Virginia	Alexandria City
Virginia	Arlington
Virginia	Caroline
Virginia	Charles City
Virginia	Chesterfield
Virginia	Fairfax
Virginia	Fauquier
Virginia	Frederick
Virginia	Hampton City
Virginia	Hanover
Virginia	Henrico
Virginia	Loudoun
Virginia	Madison
Virginia	Page

Virginia	Prince William
Virginia	Roanoke
Virginia	Rockbridge
Virginia	Stafford
Virginia	Suffolk City
Virginia	Wythe
Washington	Clallam
Washington	Clark
Washington	King
Washington	Mason
Washington	Pierce
Washington	Skagit
Washington	Spokane
Washington	Thurston
Washington	Whatcom
West Virginia	Berkeley
West Virginia	Cabell
West Virginia	Greenbrier
West Virginia	Hancock
West Virginia	Kanawha
West Virginia	Monongalia
West Virginia	Ohio
West Virginia	Wood
Wisconsin	Brown
Wisconsin	Columbia
Wisconsin	Dane
Wisconsin	Dodge
Wisconsin	Door
Wisconsin	Florence
Wisconsin	Fond Du Lac
Wisconsin	Green
Wisconsin	Jefferson
Wisconsin	Kenosha
Wisconsin	Kewaunee
Wisconsin	Manitowoc
Wisconsin	Marathon
Wisconsin	Milwaukee
Wisconsin	Oneida
Wisconsin	Outagamie
Wisconsin	Ozaukee
Wisconsin	Racine
Wisconsin	Rock
Wisconsin	Sauk
Wisconsin	Sheboygan
Wisconsin	St Croix
Wisconsin	Vernon
Wisconsin	Vilas
Wisconsin	Walworth
Wisconsin	Washington
Wisconsin	Waukesha
Wisconsin	Winnebago
Wyoming	Campbell

Wyoming	Teton

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Utility Boiler - Bituminous Coal Wall Fired	Low NOx Burner and Over Fire Air	56	Cost effectiveness is variable and based on: plant size, the total capital cost of $28.11 per kW; the fixed O&M costs of $0.43 per kW per year; and variable O&M costs of $0.08 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to wall fired coal utility boilers.	NLNBOUBCW
Utility Boiler - Bituminous Coal/ Wall Fired	Low NOx Burner	41	$850		72, 179, 222	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to wall fired coal utility boilers.	NLNBUUBCW
Utility Boiler - Coal/ Wall	Natural Gas Reburn	50	Cost effectiveness is variable and based on: plant size, the total capital cost of $32.41 per kW, and the fixed O&M of $0.49 per kW per year.		72, 184, 222, 227, 228	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to pulverized-dry bottom coal-fired electricity generation sources.	NNGR_UBCW
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	53.1	Cost effectiveness is variable and based on plant size : the total capital cost of $17.43 per kW; the fixed O&M costs of $0.27 per kW per year; and variable O&M costs of $0.029 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with cross-coupled and separated overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC3UBCT
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	58.3	Cost effectiveness is variable and based on plant size : the total capital cost of $17.43 per kW; the fixed O&M costs of $0.27 per kW per year; and variable O&M costs of $0.029 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with cross-coupled and separated overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC3UBCT2
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	33.1	Cost effectiveness is variable and based on plant size : the total capital cost of $10.96 per kW; the fixed O&M costs of $0.17 per kW per year; and variable O&M costs of $0.0 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with cross-coupled overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC1UBCT
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	43.3	Cost effectiveness is variable and based on plant size : the total capital cost of $10.96 per kW; the fixed O&M costs of $0.17 per kW per year; and variable O&M costs of $0.0 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with cross-coupled overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC1UBCT2
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with separated Overfire Air	12.71	Cost effectiveness is variable and based on plant size : the total capital cost of $15.31 per kW; the fixed O&M costs of $0.23 per kW per year; and variable O&M costs of $0.029 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with separated overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC2UBCT
Utility Boiler - Coal/ Tangential	Low NOx Coal-and-Air Nozzles with separated Overfire Air	48.3	Cost effectiveness is variable and based on plant size : the total capital cost of $15.31 per kW; the fixed O&M costs of $0.23 per kW per year; and variable O&M costs of $0.029 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx coal and air nozzles coupled with separated overfire air to reduce NOx emissions. Over-fire air stages combustion by diverting combustion air from the burners to create a fuel rich zone in the furnace. This inhibits fuel-bound nitrogen conversion in coal fired boilers. This control is applicable to tangentially-fired coal utility boilers.	NLNC2UBCT2
Utility Boiler - Coal/ Tangential	Natural Gas Reburn	50	Cost effectiveness is variable and based on: plant size, the total capital cost of $32.41 per kW, and the fixed O&M of $0.49 per kW per year.		72, 184, 222, 227, 228	Naturel gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to bituminous/subbituminous coal-fired electricity generation sources, including sources with atmospheric fluidized bed combustion.	NNGR_UBCT

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Utility Boiler - Coal/ Tangential	Selective Catalytic Reduction	90	$1550-$2066	Hg - 95%	72, 179, 217, 222, 224, 227	This control is the use of selective catalytic reduction add-on controls to tangentially coal-fired utility boilers for the reduction of NOx emissions. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to bituminous/subbituminous coal-fired electricity generation sources, including sources with atmospheric fluidized bed combustion with nameplate capacity greater than 100 MW.	NSCR_UBCT
Utility Boiler - Coal/ Tangential	Selective Non-Catalytic Reduction	35	$825-$1550		72, 229	This control is the use of selective non-catalytic reduction add-on controls to reduce NOx emissions from tangentially coal-fired utility boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). This control applies to bituminous/subbituminous coal-fired electricity generation sources, including sources with atmospheric fluidized bed combustion.	NSNCRUBCT
Utility Boiler - Coal/ Wall	Selective Catalytic Reduction	90	$1550-$2066		72, 179, 222, 224, 227	This control is the use of selective catalytic reduction add-on controls to coal/wall fired utility boilers for the reduction of NOx emissions. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to pulverized-dry bottom coal-fired electricity generation sources with a nameplate capacity greater than 100 MW.	NSCR_UBCW
Utility Boiler - Coal/ Wall	Selective Non-Catalytic Reduction	35	$825-$1550		72, 229	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to wall fired (coal) utility boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). This control applies to pulverized-dry bottom coal-fired electricity generation sources with a nameplate capacity between 25 and 100 MW.	NSNCRUBCW
Utility Boiler - Cyclone	Natural Gas Reburn	50	Cost effectiveness is variable and based on: plant size, the total capital cost of $32.41 per kW, and the fixed O&M of $0.49 per kW per year.		72, 184, 222, 227, 228	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to pulverized-dry bottom coal-fired electricity generation sources with cyclone furnaces.	NNGR_UBCY
Utility Boiler - Cyclone	Selective Catalytic Reduction	90	$1550-$2066		72, 179, 222, 224, 227	This control reduces NOx emissions using selective catalytic add-on controls on utility boilers with cyclone burners. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to bituminous/subbituminous coal-fired electricity generation sources with cyclone furnaces and nameplate capacity greater than 100 MW.	NSCR_UBCY
Utility Boiler - Cyclone	Selective Non-Catalytic Reduction	35	$825-$1550		72, 229	This control is the use of selective non-catalytic reduction add-on controls to cyclone utility boilers to reduce NOx emissions. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). This control applies to bituminous/subbituminous coal-fired electricity generation sources with cyclone furnaces.	NSNCRUBCY
Utility Boiler - Oil-Gas/ Tangential	Natural Gas Reburn	50	Cost effectiveness is variable and based on: plant size, the total capital cost of $32.41 per kW, and the fixed O&M of $0.49 per kW per year.		72, 184, 222, 227, 228	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to tangentially natural-gas fired electricity generation sources.	NNGR_UBOT
Utility Boiler - Oil-Gas/ Tangential	Selective Catalytic Reduction	80	$1550-$2066		72, 179, 222, 224, 227	This control is the selective catalytic reduction of NOx through add-on controls to tangentially fired (oil/gas) utility boilers. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to tangentially natural-gas fired electricity generation sources with nameplate capacity greater than 100 MW.	NSCR_UBOT
Utility Boiler - Oil-Gas/ Tangential	Selective Non-Catalytic Reduction	50	$825-$1550		72, 229	This control reduces NOx emissions using selective non-catalytic reduction add-on controls to tangentially fired (oil/gas) utility boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The control applies to tangentially natural-gas fired electricity generation sources.	NSNCRUBOT

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Utility Boiler - Oil-Gas/ Wall	Natural Gas Reburn	50	Cost effectiveness is variable and based on: plant size, the total capital cost of $32.41 per kW, and the fixed O&M of $0.49 per kW per year.		72, 184, 222, 227, 228	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to natural-gas fired electricity generation sources, excluding tangentially fired sources.	NNGR_UBOW
Utility Boiler - Oil-Gas/ Wall	Selective Catalytic Reduction	80	$1550-$2066		72, 179, 222, 224, 227	This control is the selective catalytic reduction of NOx through add-on controls to wall fired (oil/gas) utility boilers. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to large (>100 million Btu/hr) natural-gas fired electricity generation sources with nameplate capacity greater than 100 MW, excluding tangentially fired sources.	NSCR_UBOW
Utility Boiler - Oil-Gas/ Wall	Selective Non-Catalytic Reduction	50	$825-$1550		72, 229	This control is the use of selective non-catalytic reduction add-on controls to wall fired (oil/gas) utility boilers for the reduction of NOx emissions. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The control applies to natural-gas fired electricity generation sources, excluding tangentially fired sources.	NSNCRUBOW
Utility Boiler - Subbituminous Coal -Wall Fired	Low NOx Burner and Over Fire Air	55	Cost effectiveness is variable and based on: plant size, the total capital cost of $28.11 per kW; the fixed O&M costs of $0.43 per kW per year; and variable O&M costs of $0.08 mills per kW per year.		72, 179, 222, 224	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to wall fired (coal) utility boilers.	NLNBOUBCW2
Utility Boiler - Subbituminous Coal/ Wall Fired	Low NOx Burner	40	$850		72, 179, 222	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to wall fired coal utility boilers.	NLNBUUBCW2
Adipic Acid Manufacturing	Extended Absorption	86	$144		72, 175, 183	This control is the use of extended absorption technologies to reduce NOx emissions. This control applies to adipic acid manufacturing operations.	NEXABADMF
Adipic Acid Manufacturing	Thermal Reduction	81	$674		72	This control is the application of Thermal Reduction controls to Adipic Acid Manufacturing sources to reduce NOx emissions. Thermal reduction reduces NOx by reaction with excess fuel in a reducing environment. NOx laden stream and excess fuel mixture passes through a burner where the mixture is heated above its ignition temperature. The hot gases then pass through one or more chambers to provide sufficient residence time to ensure complete combustion.	NTHRDADMF
Ammonia - Naturel Gas-Firad Reformers	Low NOx Burner	50	$1,316 for NOx<1 tpd and $1,043 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with natural gas-fired reformers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUFRNG
Ammonia - Natural Gas-Fired Reformers	Low NOx Burner and Flue Gas Recirculation	60	$4,109 for NOx<1 tpd and $947 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with natural gas-fired reformers and uncontrolled NOx emissions greater than 10 tons per year.	NLNBFFRNG
Ammonia - Natural Gas-Fired Reformers	Oxygen Trim and Water Injection	65	$1,091 for NOx<1 tpd and $514 for NOx>1 tpd		72, 172, 175, 179, 184, 185	This control is the use of oxygen trim and water injection to reduce NOx emissions.Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control is applicable to ammonia production operations with natural gas-fired reformers and uncontrolled NOx emissions greater than 10 tons per year.	NOTWIFRNG
Ammonia - Natural Gas-Fired Reformers	Selective Catalytic Reduction	90	$2,652		72, 167, 175, 179, 224, 225, 226	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural-gas fired reformers involved in the production of ammonia with uncontrolled NOx emissions greater than 10 tons per year.	NSCRFRNG
Ammonia - Natural Gas-Fired Reformers	Selective Non-Catalytic Reduction	50	$6,211 for NOx<1 tpd and $2,520 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformer with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRFRNG

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Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Ammonia - Oil-Fired Reformers	Low NOx Burner	50	$642 for NOx<1 tpd and $690 for NOx>1 tpd		72	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone end reducing the amount of oxygen available in another. This control is applicable to oil-fired ammonia reformers.	NLNBUFROL
Ammonia - Oil-Fired Reformers	Low NOx Burner and Flue Gas Recirculation	60	$1,798 for NOx<1 tpd and $626 for NOx>1 tpd		72	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone end reducing the amount of oxygen available in another. This control is applicable to ammonia production operations with oil-fired reformers and uncontrolled NOx emissions greater than 10 tons per year.	NLNBFFROL
Ammonia - Oil-Fired Reformers	Selective Catalytic Reduction	80	$2,375 for NOx<1 tpd and $1,300 for NOx>1 tpd		72	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil fired reformers involved in the production of ammonia with uncontrolled NOx emissions greater than 10 tons per year.	NSCRFROL
Ammonia - Oil-Fired Reformers	Selective Non-Catalytic Reduction	50	$4,141 for NOx<1 tpd and $1,685 for NOx>1 tpd		72	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to ammonia production natural gas fired reformers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRFROL
Ammonia Products - Feedstock Desulfurization	Low NOx Burner and Flue Gas Recirculation	60	$4,109 for NOx<1 tpd and $947 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to feedstock desulfurization processes in ammonia products operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFAPFD
Asphalt Plant Manufacture	Low NOx Burner and Flue Gas Recirculation	30-50	N/A		171	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to asphalt plant manufacturing sources.	N/A
Asphaltic Concrete - Rotary Dryer - Conventional Plant	Low NOx Burner	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to construction operations with rotary driers and uncontrolled NOx emissions greater than 10 tons per year.	NLNBUACCP
By-Product Coke Manufacturing - Oven Underfiring	Selective Non-Catalytic Reduction	60	$2,632		72, 172, 175, 179, 181	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologiea basad on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to all by-product coke manufacturing operations with oven underfiring and uncontrolled NOx emissions greater than 10 tons per year.	NSNCRCMOU
Cement Kilns	Biosolid Injection Technology	23	$407		72, 168	This control is the use of biosolid injection to reduce NOx emissions. This control applies to cement kilns.	NBINTCEMK
Cement Kilns	Changing feed composition	25-40	$587		171, 234	This control is changing the cement formulation by adding waste iron to lower the clinkering temperatures and supress NOx. This process can decrease NOx emissions and also increase production by 15%. This control is applicable to wet- and dry-process kilns, as well as those with preheaters or precalciners.	N/A
Cement Kilns	Process Control Systems	<25	N/A		171, 234	This control is the modification of the cement production process to improve fuel efficiency, increase capacity and kiln operational stability. NOx reductions result from the increase in productivity and reduced energy use. Two process controls thet specifically target NOx emissions are continuous emissions monitoring systems and the incorporation of a small amount of steel slag to the raw kiln feed to increase thermal efficiency. This control is applicable to wet- and dry-process kilns, as well as those with preheaters or precalciners.	N/A
Cement Manufacturing - Dry Process	Selective Catalytic Reduction	80	$4,062		72	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to dry-process cement manufacturing and Natural Gas Cement Kilns with uncontrolled NOx emissions greater than 10 tons per year.	NSCRCMDY
Cement Manufacturing - Dry Process	Selective Catalytic Reduction	90	$5,588		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control applies to dry-process cement manufacturing and Natural Gas Cement Kilns with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRCMDY

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Cement Manufacturing - Dry Process	Selective Non-Catalytic Reduction - Ammonia	50	$1,364		72, 172, 175, 179, 198	This control is the reduction of NOx emission through ammonia based selective non-catalytic reduction add on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to dry-process cement manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSNCNCMDY
Cement Manufacturing - Dry Process	Selective Non-Catalytic Reduction - Urea	50	$1,236		72, 175, 179, 198	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to dry-process cement manufacturing with uncontrolled NOx emissions greater then 10 tons per year.	NSNCRCMDY
Cement Manufacturing - Dry Process or Wet Process	Low NOx Burner	25	$577		72, 175, 179, 198, 199	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to dry-process or wet-process cement manufacturing operations with indirect-fired kilns with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUCMDY and NLNBUCMWT
Cement Manufacturing - Dry Process or Wet Process	Mid-Kiln Firing	30	$72		72, 175, 179, 198, 199	This control is the use of mid- kiln firing to reduce NOx emissions. Mid-kiln firing is the injection of solid fuel into the calcining zone of a long kiln. This allows for part of the fuel to be burned at a lower temperature, reducing NOx formation. This control applies to wet-process and dry-process cement manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NMKFRCMDY and NMKFRCMWT
Cement Manufacturing - Wet Process	Selective Catalytic Reduction	90	$4,776		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control applies to wet-process cement manufacturing with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRCMWT
Ceramic Clay Manufacturing - Drying	Low NOx Burner	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd		72, 175, 179, 198	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to drying processes at ceramic clay manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUCCMD
Coal Cleaning-Thermal Dryer - Fluidized Bed	Low NOx Burner	50	$1,108 for NOx<1 tpd and $222 for NOx>1 tpd		72, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to thermal drying processes at coal cleaning operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUCCFB
Combustion Turbine - Aeroderivative Gas Turbines	Water Injection	40	$45,460		160, 169	This control is the use of water injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year.	NWIGTAGT
Combustion Turbines - Natural Gas	Low NOx Burner	68% for small sources, 84% for large sources	$490 for NOx<1 tpd and $100 for NOx>1 tpd		72, 172, 175, 179, 223	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to natural gas fired turbines with uncontrolled NOx emissions greater then 10 tons per year.	NLNBUGTNG
Combustion Turbines - Natural Gas	Selective Catalytic Reduction and Low NOx Burner	94	$4,125 for NOx<1 tpd and $963 for NOx>1 tpd		72, 172, 175, 179, 223, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.	NSCRLGTNG
Combustion Turbines - Natural Gas	Selective Catalytic Reduction and Steam Injection	95	$3,226 for NOx<1 tpd and $1,348 for NOx>1 tpd		72, 172, 175, 179, 223, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control applies to natural gas fired turbines with NOx emissions greater than 10 tons per year.	NSCRSGTNG
Combustion Turbines - Natural Gas	Selective Catalytic Reduction and Water Injection	95	$4,382 for NOx<1 tpd and $1,814 for NOx>1 tpd		72, 172, 175, 179, 223, 224	This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year.	NSCRWGTNG
Combustion Turbines - Natural Gas	Steam Injection	80	$1,669 for NOx<1 tpd and $802 for NOx>1 tpd		72, 172, 175, 184, 223	This control is the use of steam injection to reduce NOx emissions. Steam is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The steam can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year.	NSTINGTNG

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Combustion Turbines - Natural Gas	Water Injection	76	$2,423 for NOx<1 tpd and $1,172 for NOx>1 tpd		72, 172, 175, 184, 223	This control is the use of water injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired gas turbines with uncontrolled NOx emissions greater than 10 tons per year.	NWTINGTNG
Combustion Turbines for Stationary Sources - Oil or Jet Fuel	Selective Catalytic Reduction and Water Injection	90	$3,691 for NOx<1 tpd and $1,621 for NOx>1 tpd		72, 172, 175, 179, 223, 224	This control is the selective catalytic reduction of NOx through add-on controls in combination with water injection. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired and jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year.	NSCRWGTOL and NSCRWGTJF
Combustion Turbines for Stationary Sources - Oil or Jet Fuel	Water Injection	68	$2,070 for NOx<1 tpd and $1,043 for NOx>1 tpd		72, 172, 175, 184, 223	This control is the use of water injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to oil turbines and jet fuel-fired turbines with uncontrolled NOx emissions greater than 10 tons per year.	NWTINGTJF and NWTINGTOL
Commercial/ Institutional or Industrial Incinerators	Selective Non-Catalytic Reduction	45	$1,814		72, 172, 175, 179, 202	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to commercial/institutional incinerators and industrial incinerators with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRCIIN and NSNCRIDIN
Conventional Coating of Products - Acid Cleaning Bath	Low NOx Burner	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to acid cleaning bath/conversion coating processes at metal product fabricating operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUCCAB
External Combustion Boilers - Electric Generation - Natural Gas (Tangential or Non-Tangential Firing)	Natural Gas Redum	50	$2,352		168	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to Natural Gas external combustion boilers used for electricity generation.	NNGRECBNG1, NNGRECBNG2, and NNGRECBNG3
External Combustion Boilers - Electricity Generation- Anthracite Coal or Subbituminous/ Bituminous Coal	Selective Non-Catalytic Reduction	40	$1,370		168	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to wall fired (coal) utility boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). This control applies to pulverized anthracite coal-fired electricity generation sources and bituminous/subbituminous coal-fired electricity generation sources.	NSNCRECBAN and NSNCRECBSB
External Combustion Boilers for Electricity Generation - Residual Oil or Solid Waste Combustion	Selective Non-Catalytic Reduction	50	$2,694		168	This control is the use of selective non-catalytic reduction add-on controls to wall fired (oil/gas) utility boilers for the reduction of NOx emissions. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). The control applies to Residual Oil (Grade 6 oil) burning electricity generation sources, excluding tangentially fired sources and solid waste combustors used for electricity generation.	NSNCRECBR and NSNCRECBSW
External Combustion Boilers, Electricity Generation, Distillate Oil	Selective Non-Catalytic Reduction	50	$4,868		168	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to wall fired (coal) utility boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) with a nitrogen based reducing reagent, such as ammonia or urea, to reduce the NOx into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil external combustion boilers.	NSNCRECBDO
Fluid Catalytic Cracking Units - Cracking Unit	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to fluid catalytic cracking units with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFFCCU
Fluid Catalytic Cracking Units - Cracking Unit	Selective Catalytic Reduction	90	$4,167		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control is applicable to fluid catalytic cracking units with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRFFCCU
Furnaces - Natural Gas	Low NOx Burner	50	$915		72, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to natural gas fired equipment with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUFFNG
Glass Manufacturing - Container	Cullet Preheat	25	$1,509		72, 175, 182	This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to container glass manufacturing operations.	NCLPTGMCN

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Glass Manufacturing - Container	Electric Boost	10	$11,475		72, 175, 182	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to container glass manufacturing operations.	NELBOGMCN
Glass Manufacturing - Container	OXY-Firing	85	$7,367		72	This control is the use of Oxy-firing in container glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing."	NOXYFGMCN
Glass Manufacturing - Container	Selective Catalytic Reduction	75	$3,531		72, 172, 175, 179, 182, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to glass-container manufacturing processes with uncontrolled NOx emissions greater than 10 tons per year.	NSCRGMCN
Glass Manufacturing - Container	Selective Non-Catalytic Reduction	40	$2,841		72172, 175, 179, 182, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to glass-container manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRGMCN
Glass Manufacturing - Container or Flat Glass	Low NOx Burner	40	$1,123		72, 175, 179, 182	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to flat glass and container glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUGMCN and NLNBUGMFT
Glass Manufacturing - Flat	Electric Boost	10	$3,724		72, 175, 182	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to flat glass manufacturing operations.	NELBOGMFT
Glass Manufacturing - Flat	OXY-Firing	85	$3,049		72	This control is the use of Oxy-firing in flat glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing"	NOXYFGMFT
Glass Manufacturing - Flat	Selective Catalytic Reduction	75	$5,409 for NOx<1 tpd and $1,140 for NOx>1 tpd		72, 172, 175, 179, 182, 186, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSCRGMFT
Glass Manufacturing - Flat	Selective Non-Catalytic Reduction	40	$1,188		72, 172, 175, 179, 182, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into moleculer nitrogen (N2) and water vapor (H2O). This control applies to flat-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRGMFT
Glass Manufacturing - General	OXY-Firing	85	$5,155		187	This control is the use of Oxy-firing in glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing."	NDOXYFGMG
Glass Manufacturing - Pressed	Cullet Preheat	25	$1,300		72, 175, 182	This control is the use of cullet preheat technologies to reduce NOx emissions from glass manufacturing operations. This control is applicable to pressed glass manufacturing operations.	NCUPHGMPD
Glass Manufacturing - Pressed	Electric Boost	10	$3,724 for NOx<1 tpd and $14,059 for NOx>1 tpd		72, 175, 182	This control is the use of electric boost technologies to reduce NOx emissions from glass manufacturing operations. This control applies to pressed glass manufacturing operations.	NELBOGMPD
Glass Manufacturing - Pressed	Low NOx Burner	40	$2,407		175, 179, 182	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to pressed glass manufactuing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUGMPD
Glass Manufacturing - Pressed	OXY-Firing	85	$6,259		72	This control is the use of Oxy-firing in pressed glass manufacturing furnaces to reduce NOx emissions. Oxygen enrichment refers to the substitution of oxygen for nitrogen in the combustion air used to burn the fuel in a glass furnace. Oxygen enrichment above 90 percent is sometimes called "oxy-firing"	NOXYFGMPD
Glass Manufacturing - Pressed	Selective Catalytic Reduction	75	$4,061		72, 172, 175, 179, 182, 186, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to pressed-glass manufacturing operations, and uncontrolled NOx emissions greater than 10 tons per year.	NSCRGMPD
Glass Manufacturing - Pressed	Selective Non-Catalytic Reduction	40	$2,632		72, 172, 175, 179, 182, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to pressed-glass manufacturing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRGMPD

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More information	Description/Notes/Caveats	CoST Control Abbreviation
Industrial Incinerators	Selective Catalytic Reduction	90	$3,748		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to industrial incinerators IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRIDIN
Industrial Natural Gas Internal Combustion Engines - 4cycle (rich)	Selective Non-Catalytic Reduction	90	$509		168	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to industrial Natural Gas rich burn internal combustion engines.	NSNCRINGI4
Industrial Natural Gas Internal Combustion Engines, 2cycle (lean)	Low Emission Combustion	87	$626		168	This control is the application of low emission combustion firing techniques to gas-fired lean burn internal conbustion engines.	NLECINGIC2
Industrial/ Commercial/ Institutional Boilers - Bagasse	Selective Non-Catalytic Reduction - Urea	55	$2,311 for NOx<1 tpd and $1,493 for NOx>1 tpd		72	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to bagasse IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBGA
Industrial/ Commercial/ Institutional Boilers - Coal	Selective Catalytic Reduction	80	$2,373 for NOx<1 tpd and $971 for NOx>1 tpd		174, 175	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal ICI boilers with NOx emissions greater than 10 tons per year.	NSCRIBCOAL
Industrial/ Commercial/ Institutional Boilers - Coal	Selective Non-Catalytic Reduction	40	$2,297 for NOx<1 tpd and $1,424 for NOx>1 tpd		174, 169	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBC
Industrial/ Commercial/ Institutional Boilers - Coal or Petroleum Coke	Low NOx Burner	50	$2,343 for NOx<1 tpd and $1,749 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to coal/wall fired ICI boilers and Petroleum coke fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUIBCW and NLNBUIBCK
Industrial/ Commercial/ Institutional Boilers - Coal or Petroleum Coke - Wall Fired	Selective Non-Catalytic Reduction	40	$1,669 for NOx<1 tpd and $1,348 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to wall fired (coal) IC boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal-fired and petroleum coke-fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBCW and NSNCRIBCK
Industrial/ Commercial/ Institutional Boilers - Coal/ Bituminous	Low NOx Burner and Over Fire Air	51	$1,373 for NOx<1 tpd and $434 for NOx>1 tpd		174, 169	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to bituminous coal Industrial/Commercial/Institutional (ICI) boilers.	NLNBOFAICB
Industrial/ Commercial/ Institutional Boilers - Coal/ Subbituminous	Low NOx Burner	51	$942 for NOx<1 tpd and $284 for NOx>1 tpd		174, 169	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to subbituminous coal industrial/commerial/institutional boilers.	NLNBICB
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Coal Reburn	50	$2,520 for NOx<1 tpd and $481 for NOx>1 tpd		72, 172, 175, 165, 208	This control reduces NOx emissions through coal reburn. This control is applicable to coal/cyclone ICI boilers.	NCLRBIBCC
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Natural Gas Reburn	55	$2,520 for NOx<1 tpd and $481 for NOx>1 tpd		72, 172, 175, 179, 184, 185, 228	Natural gas reburning (NGR) involves add-on controls to reduce NOx emissions. NGR is a combustion control technology in which part of the main fuel heat input is diverted to locations above the main burners, called the reburn zone. As flue gas passes through the reburn zone, a portion of the NOx formed in the main combustion zone is reduced by hydrocarbon radicals and converted to molecular nitrogen (N2). This control applies to coal/cyclone ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NNGRIBCC
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Selective Catalytic Reduction	90	$1,316 for NOx<1 tpd and $1,123 for NOx>1 tpd		72, 172, 175, 179, 165, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal/cyclone ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSCRIBCC
Industrial/ Commercial/ Institutional Boilers - Coal/ Cyclone	Selective Non-Catalytic Reduction	35	$1,348 for NOx<1 tpd and $1,123 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal/cyclone IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBCC

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Industrial/ Commercial/ Institutional Boilers - Coal/ Fluidized Bed Combustion	Selective Catalytic Reduction	90	$1,397		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to fluidized bed combustion coal ICI boilers.	NDSCRIBCF
Industrial/ Commercial/ Institutional Boilers - Coal/ Fluidized Bed Combustion	Selective Non-Catalytic Reduction - Urea	75	$1,444 for NOx<1 tpd and $1,075 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal-fired/fluidized bed combustion IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBCF
Industrial/ Commercial/ Institutional Boilers - Coal/ Stoker	Selective Catalytic Reduction	90	$3,051		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal/stoker IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRIBCS
Industrial/ Commercial/ Institutional Boilers - Coal/ Stoker	Selective Non-Catalytic Reduction	40	$1,629 for NOx<1 tpd and $1,311 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls to coal/stoker IC boilers. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal/stoker IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBCS
Industrial/ Commercial/ Institutional Boilers - Coal/ Subbituminous	Low NOx Burner and Over Fire Air	65	$1,077 for NOx<1 tpd and $339 for NOx>1 tpd		174, 169	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to subbituminous coal Industrial/Commercial/Institutional (ICI) boilers.	NLNBOFAICS
Industrial/ Commercial/ Institutional Boilers - Coal/ Wall	Selective Catalytic Reduction	90	$2,022 for NOx<1 tpd and $1,717 for NOx>1 tpd		72, 172, 175, 179, 185, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures.This control applies to coal/wall IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSCRIBCW
Industrial/ Commercial/ Institutional Boilers - Distillate Oil	Selective Catalytic Reduction	90% for small sources, 80% for large sources	$3,566		72, 175, 179, 224, 225, 226	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to distillate oil-fired ICI boilers with NOx emissions greater than 10 tons per year.	NSCRIBDO
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Low NOx Burner	50	$1,894 for NOx<1 tpd and $3,322 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to Oil and LPG ICI boilers with uncontrolled NOx emissions greater than 10 tons per year	NLNBUIBDO and NLNBUIBLP
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Low NOx Burner and Flue Gas Recirculation	60	$3,996 for NOx<1 tpd and $1,220 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to distillate oil-fired ICI boilers and LPG-fired ICI Boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFIBDO and NLNBFIBLP
Industrial/ Commercial/ Institutional Boilers - Distillate Oil or LPG	Selective Non-Catalytic Reduction	50	$7,447 for NOx<1 tpd and $3,033 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil and LPG-fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBDO and NSNCRIBLP
Industrial/ Commercial/ Institutional Boilers - Gas	Low NOx Burner and Flue Gas Recirculation + Over Fire Air	80	$1,416 for NOx<1 tpd and $408 for NOx>1 tpd		174, 175	This control is the use of low NOx burner (LNB) technology , flue gas recirculation (FGR), and over fire air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to gas Industrial/Commercial/Institutional (ICI) boilers.	NLNBFGROFA
Industrial/ Commercial/ Institutional Boilers - Gas	Low NOx Burner and Over Fire Air	60	$1,158 for NOx<1 tpd and $310 for NOx>1 tpd		174, 169	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to gas Industrial/Commercial/Institutional (ICI) boilers.	NLNBOAICBG
Industrial/ Commercial/ Institutional Boilers - Gas	Selective Catalytic Reduction	80	$3,250 for NOx<1 tpd and $1,093 for NOx>1 tpd		174, 175	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSCRICBG

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Industrial/ Commercial/ Institutional Boilers - Gas	Selective Non-Catalytic Reduction	40	$1,166 for NOx<1 tpd and $310 for NOx>1 tpd		174, 169	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRICBG
Industrial/ Commercial/ Institutional Boilers - Liquid Waste	Selective Catalytic Reduction	90	$1,890		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to liquid waste ICI boilers with NOx emissions greater than 10 tons per year.	NDSCRIBLW
Industrial/ Commercial/ Institutional Boilers - LPG	Selective Catalytic Reduction	90	$4,747		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to LPG ICI boilers with NOx emissions greater than 10 tons per year.	NDSCRIBLP
Industrial/ Commercial/ Institutional Boilers - Municipal Solid Waste/ Stoker	Selective Non-Catalytic Reduction - Urea	55	$2,712 for NOx<1 tpd and $2,006 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to solid waste/stoker IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBMS
Industrial/ Commercial/ Institutional Boilers - Natural Gas	Selective Non-Catalytic Reduction	50	$6,211 for NOx<1 tpd and $2,520 for NOx>1 tpd		72	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBNG
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Low NOx Burner	50	$1,316 for NOx<1 tpd and $1,043 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas and process gas fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUIBNG and NLNBUIBPG
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Low NOx Burner and Flue Gas Recirculation	60	$4,109 for NOx<1 tpd and $947 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired and process gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFIBNG and NLNBFIBPG
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Oxygen Trim and Water Injection	65	$1,091 for NOx<1 tpd and $514 for NOx>1 tpd		72, 172, 175, 179, 184, 185	This control is the use of Oxygen Trim and Water Injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired and process gas-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NOTWIIBNG and NOTWIIBPG
Industrial/ Commercial/ Institutional Boilers - Natural Gas or Process Gas	Selective Catalytic Reduction	90	$2,852		72, 175, 179, 224, 225, 226	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired and process gas-fired ICI boilers with NOx emissions greater than 10 tons per year.	NSCRIBNG and NDSCRIBPG
Industrial/ Commercial/ Institutional Boilers - Oil	Low NOx Burner and Over Fire Air	50	$1,166 for NOx<1 tpd and $339 for NOx>1 tpd		174, 169	This control is the use of low NOx burner (LNB) technology and Over Fire Air (OFA) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to oil Industrial/Commercial/Institutional (ICI) boilers.	NLNBOAICBO
Industrial/ Commercial/ Institutional Boilers - Oil	Selective Catalytic Reduction	80	$2,232 for NOx<1 tpd and $842 for NOx>1 tpd		174, 175	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSCRICBO
Industrial/ Commercial/ Institutional Boilers - Oil	Selective Non-Catalytic Reduction	40	$2,623 for NOx<1 tpd and $1,646 for NOx>1 tpd		174, 169	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to oil IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRICBO
Industrial/ Commercial/ Institutional Boilers - Petroleum Coke	Selective Catalytic Reduction	90	$1,941		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coke ICI boilers with NOx emissions greater than 10 tons per year.	NDSCRIBCK

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Low NOx Burner	50	\$642 for NOx<1 tpd and \$690 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired ICI boilers and liquid waste fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUIBRO and NLNBUIBLW
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Low NOx Burner and Flue Gas Recirculation	60	\$1,798 for NOx<1 tpd and \$626 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired and liquid waste-fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFIBRO and NLNBFIBLW
Industrial/ Commercial/ Institutional Boilers - Residual Oil or Liquid Waste	Selective Non-Catalytic Reduction	50	\$4,141 for NOx<1 tpd and \$1,685 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to residual oil and liquid waste-fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBRO and NSNCRIBLW
Industrial/ Commercial/ Institutional Boilers - Wood/ Bark/ Fluidized Bed Combustion	Selective Non-Catalytic Reduction - Ammonia	55	\$2,119 for NOx<1 tpd and \$1,541 for NOx>1 tpd		72	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to wood fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBWF
Industrial/ Commercial/ Institutional Boilers - Wood/ Bark/ Stoker	Selective Non-Catalytic Reduction - Urea	55	\$2,311 for NOx<1 tpd and \$1,493 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through urea based selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to wood/bark fired IC boilers with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRIBWS
Industrial/ Commercial/ Institutional Boilers - Wood/ Bark/ Waste	Selective Catalytic Reduction	90	\$3,946		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to industrial/commercial/institutional boilers fired with wood bark or waste.	NDSCRIBW
Industrial/ Commercial/ Institutionel Space and Water Heaters	Low NOx Burner	7	\$1,974		149, 169	The South Coast and Bay Area AQMDs set emission limits for water heaters and space heaters. This control is based on the installation of low-NOx space heaters and water heaters in commercial and institutional sources for the reduction of NOx emissions.The control applies to natural gas burning space heaters and water heaters.	NLNBICISWH
In-Process - Bituminous Coal - Cement Kilns or Lime Kilns	Selective Catalytic Reduction	90	\$2,554		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to bituminous coal-fired cement kilns and coal-fired lime kilns with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRBCCK and NDSCRBCLK
In-Process - Bituminous Coal - Cement Kilns or Lime Kilns	Selective Non-Catalytic Reduction - Urea	50	\$928		72, 172, 175, 179, 198	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to bituminous coal-fired cement kilns and lime kilns with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRBCCK and NSNCRBCLK
In-Process - Process Gas - Coke Oven Gas	Selective Catalytic Reduction	90	\$7,679		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to process gas fired ICI boilers with NOx emissions greater than 10 tons per year.	NDSCRFPGCO
In-Process - Process Gas - Coke Oven Gas	Selective Catalytic Reduction	90	\$5,970		167	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process process gas usage from Coke Oven Gas.	NDSCRUPGCO
In-Process Fuel Use - Natural Gas	Selective Catalytic Reduction	90	\$5,970		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process natural gas usage and uncontrolled NOx emissions greater than 10 tons per year.	NDSCRUNGGN
In-Process Fuel Use - Natural Gas or Coke Oven Process Gas	Low NOx Burner	50	\$3,531 for NOx<1 tpd and \$2,889 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to operations with in-process coke oven gas usage and natural gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUNGGN and NLNBUPGCO

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
In-Process Fuel Use - Residual Oil	Selective Catalytic Reduction	90	$5,374		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) end water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process residual oil usage and uncontrolled NOx emissions greater than 10 tons per year.	NDSCRUROGN
In-Process Fuel Use - Bituminous Coal	Selective Catalytic Reduction	90	$3,649		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applias to operations with general (in process) bituminous coal use and uncontrolled NOx emissions greater than 10 tons per year.	NDSCRBCGN
In-Process Fuel Use - Bituminous Coal - Gen	Selective Non-Catalytic Reduction	40	$2,022 for NOx<1 tpd and $1,509 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to operations with general (in process) bituminous coal use and uncontrolled NOx emissions greater than 10 tons per year.	NSNCRBCGN
In-Process -Process Gas -Coke Oven/ Blast Furnace	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to in-process coke/blast furnaces and uncontrolled NOx emissions greater than 10 tons per year.	NLNBFCOBF
Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio	20	$2,520 for NOx<1 tpd and $610 for NOx>1 tpd		72, 106, 175, 172	This control is the use of air/fuel ratio adjustment to reduce NOx emissions. This control applies to gasoline powered internal combustion engines with uncontrolled NOx emissions greater than 10 tons per year.	NAFRICGS
Internal Combustion Engines - Gas	Adjust Air to Fuel Ratio and Ignition Retard	30	$2,311 for NOx<1 tpd and $738 for NOx>1 tpd		72, 169	This control is the use of air/fuel and ignition retard to reduce NOx emissions. This control applies to gasoline powered internal combustion engines with uncontrolled NOx emissions greater than 10 tons per year.	NAFRIICGS
Internal Combustion Engines - Gas	Ignition Retard	20	$1,637 for NOx<1 tpd and $883 for NOx>1 tpd		72, 106, 172, 175	This applies to gasoline powered IC engines with uncontrolled NOx emissions greater than 10 tons per year.	NIRICGS
Internal Combustion Engines - Gas	Low Emissions Combustion (Low Speed)	87	$2,696 for NOx<1 tpd and $1,011 for NOx>1 tpd		72, 106, 172, 175	This control is the application of Low Emissions (Low Speed) technology to reduce NOx emissions. This control applies to natural gas powered IC engines with uncontrolled NOx emissions greater than 10 tons per year. The low emissions combustion modification reduces NOx by increasing the Air-to-Fuel ratio through extensive retrofit of the engines and ancillary system. This allows the engine to operate at very lean A/F ratios, which lead to low amounts of NOx formation.	NLELSICGS
Internal Combustion Engines - Gas	Low Emissions Combustion (Medium Speed)	87	$610		72, 106, 172, 175	This control is the application of Low Emissions (Medium Speed) technology to reduce NOx emissions.This control applies to natural gas powered IC engines with uncontrolled NOx emissions greater than 10 tons per year. The low emissions combustion modification reduces NOx by increasing the Air-to-Fuel ratio through extensive retrofit of the engines and ancillary system. This allows the engine to operate at very lean A/F ratios, which lead to low amounts of NOx formation.	NLEMSICGS
Internal Combustion Engines - Gas	Selective Catalytic Reduction	90	$4,444		72, 106, 172, 175, 179, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applias to gas-fired IC engines with uncontrolled NOx emissions greater than 10 tons per year.	NSCRICGS
Internal Combustion Engines - Gas	Selective Non-Catalytic Reduction	90	$836	VOC - 50%, CO - 90%	72, 106, 199, 231, 232	NSCR is achieved by placing a catalyst in the exhaust stream of the engine. The exhaust passes over the catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20 (NJDEP, 2003). Typical exhaust temperatures for effective removal of NOx are 800-1200 dagrees Fahrenheit. An oxidation catalyst using edditional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness.	NSNCRICGS
Internal Combustion Engines - Gas or Diesel or LPG or Oil-Fired	Selective Catalytic Reduction	80	$3,756 for NOx<1 tpd and $1,477 for NOx>1 tpd		72, 106, 172, 175, 179, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls ara post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to gas, diesel, oil and LPG-fired IC engines with uncontrolled NOx emissions greater than 10 tons per year.	NSCRICGD and NSCRICOL
Internal Combustion Engines - Gas/ Diesel/ Oil/ LPG	Ignition Retard	25	$1,236 for NOx<1 tpd and $786 for NOx>1 tpd		72, 106, 172, 175	This control is the use of ignition retard technologies to reduce NOx emissions. This applies to Gas, LPG, Diesel, and oil IC engines with NOx emissions greater than 10 tons per year.	NIRICGD and NIRICOL

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Iron & Steel Mills - Annealing	Low NOx Burner	50	$915		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUISAN
Iron & Steel Mills - Annealing	Low NOx Burner and Flue Gas Recirculation	60	$1,204		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFISAN
Iron & Steel Mills - Annealing	Low NOx Burner and Selective Catalytic Reduction	90	$6,548		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSISAN
Iron & Steel Mills - Annealing	Low NOx Burner and Selective Noncatalytic Reduction	80	$2,761		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBNISAN
Iron & Steel Mills - Annealing	Selective Catalytic Reduction	90	$6,351		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to iron and steel annealing operations with NOx emissions greater than 10 tons per year.	NDSCRISAN
Iron & Steel Mills - Annealing	Selective Catalytic Reduction	90	$6,384		72, 175, 179, 186, 224, 225, 226	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to iron and steel annealing operations with NOx emissions greater than 10 tons per year.	NSCRISAN
Iron & Steel Mills - Annealing	Selective Catalytic Reduction	99	$6,384		72, 175, 179, 186, 224, 225, 226	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to iron and steel annealing operations with NOx emissions greater than 10 tons per year.	NSCRISAN
Iron & Steel Mills - Annealing	Selective Non-Catalytic Reduction	60	$2,632		72, 172, 175, 179, 181, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to iron and steel mill annealing operations with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRISAN
Iron & Steel Mills - Galvanizing	Low NOx Burner	50	$786		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel galvanizing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUISGV
Iron & Steel Mills - Galvanizing	Low NOx Burner and Flue Gas Recirculation	60	$931		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel galvanizing operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFISGV
Iron & Steel Mills - Reheating	Low Excess Air	13	$2,119		72, 106, 172, 175, 181, 184	The reduction in NOx emissions is achieved through the use of low excess air techniques, such that there is less available oxygen convert fuel nitrogen to NOx. This control applies to iron & steel reheating furnaces.	NLEAISRH
Iron & Steel Mills - Reheating	Low NOx Burner	66	$481		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel reheating operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUISRH

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Iron & Steel Mills - Reheating	Low NOx Burner and Flue Gas Recirculation	77	$610		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to reheating processes in iron and steel mills with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFISRH
Iron Production - Blast Furnace - Blast Heating Stoves	Low NOx Burner and Flue Gas Recirculation	77	$610		72, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to reheating processes in iron production operations with blast heating stoves ant uncontrolled NOx emissions greater than 10 tons per year.	NLNBFIPBH
Lean Burn Internal Combustion Engine - Gas	Low Emission Combustion	87	$640		172, 169	This control is the application of Low Emission Combustion firing techniques to gas-fired lean burn IC engines.	NLECICEGAS
Lime Kilns	Low NOx Burner	30	$899		72, 175, 179, 198	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to lime kilns with uncontrolled NOx emissions greater than 10 tons per year.	NLNBULMKN
Medical Waste Incinerators	Selective Non-Catalytic Reduction	45	$7,238		72, 172, 175, 179, 230	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). This control applies to medical waste incinerators with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRMWIN
Natural Gas Production - Compressors	Selective Catalytic Reduction	20	$4,444 for NOx<1 tpd and $855 for NOx>1 tpd		72, 106, 172, 175, 179, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to compressors used in natural gas production operations with NOx emissions greater than 10 tons per year.	NSCRNGCP
Nitric Acid Manufacturing	Extended Absorption	95	$770		72, 175, 183	This control is the use of extended absorption technologies to reduce NOx emissions. This control applies to nitric acid manufacturing operations.	NEXABNAMF
Nitric Acid Manufacturing	Non-Selective Catalytic Reduction	98	$883		72, 73, 175, 179, 183	NSCR is achieved by placing a catalyst in the exhaust stream of the engine. The exhaust passes over the catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N_2, CO_2 and H20 (NJDEP, 2003). Typical exhaust temperatures for effective removal of NOx are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can be installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness.	NNSCRNAMF
Nitric Acid Manufacturing	Selective Catalytic Reduction	90	$979		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to nitric acid manufacturing operations with NOx emissions greater than 10 tons per year.	NDSCRNAMF
Plastics Product Specific - Acrylonitrile-Butadiene-Styrene (ABS) Resin	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to with acrylonitrile-butadiene-styrene plastic production uncontrolled NOx emissions greater than 10 tons per year.	NLNBFPPAR
Primary Copper Smelters - Reverberatory Smelter Furnace	Low NOx Burner and Flue Gas Recirculation	60	$1,204		72	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to primary copper smelting operations.	NLNBFCSRS
Process Heaters	Low NOx Burner and Flue Gas Recirculation	50	$915		179, 175	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFGRPH
Process Heaters - Distillate Oil	Low NOx Burner and Selective Catalytic Reduction	90	$10,471		72, 167, 172, 175, 179, 224, 225	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N_2) and water vapor (H_2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to distillate oil-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHDO

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Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Process Heaters - Distillate Oil	Selective Catalytic Reduction	75	$14,814 for NOx<1 tpd and $9,678 for NOx>1 tpd		72, 172, 175, 179, 186, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to distillate oil-fired process heaters with NOx emissions greater than 10 tons per year.	NSCRPHDO
Process Heaters - Distillate Oil or LPG	Low NOx Burner	45	$5,569 for NOx<1 tpd and $1,557 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to distillate oil-fired process heaters and LPG fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUPHDO and NLNBPHLP
Process Heaters - Distillate Oil or LPG	Low NOx Burner and Flue Gas Recirculation	48	$6,821 for NOx<1 tpd and $2,696 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to distillate-fired process heatersand LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFPHDO and NLNBFPHLP
Process Heaters - Distillate Oil or LPG	Low NOx Burner and Selective Noncatalytic Reduction	78	$5,810 for NOx<1 tpd and $3,017 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and selective non catalytic reduction (SNCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to LPG-fired and distillate oil-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBNPHDO and NLNBNPHLP
Process Heaters - Distillate Oil or LPG	Selective Non-Catalytic Reduction	60	$5,104 for NOx<1 tpd and $2,761 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil-fired and LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRPHDO and NSNCRPHLP
Process Heaters - Distillate Oil or LPG	Ultra-Low NOx Burner	74	$3,435 for NOx<1 tpd and $979 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of ultra-low NOx burner (ULNB) add-on technologies to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil-fired process heaters and LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NULNBPHDO and NULNBPHLP
Process Heaters - LPG	Low NOx Burner	50	$6,003		72, 175	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to LPG-fired process heaters.	NLNBUPHLG
Process Heaters - LPG	Low NOx Burner and Flue Gas Recirculation	48	$6,741 for NOx<1 tpd and $5,136 for NOx>1 tpd		72, 169, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFPHLG
Process Heaters - LPG	Low NOx Burner and Selective Catalytic Reduction	92	$18,457 for NOx<1 tpd and $14,637 for NOx>1 tpd		72, 172, 175, 1798, 186	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHLP
Process Heaters - Natural Gas	Low NOx Burner and Selective Catalytic Reduction	80	$14,920		72, 167, 172, 175, 179, 186, 224	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to natural gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHNG
Process Heaters - Natural Gas or Process Gas	Low NOx Burner	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired and process gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUPHNG and NLNBUPHPG

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Process Heaters - Natural Gas or Process Gas	Low NOx Burner and Selective Catalytic Reduction	90	$14,920		72, 167, 172, 175, 179, 186, 224	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to natural gas-fired and process gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHNG and NLNBSPHPG
Process Heaters - Natural Gas or Process Gas	Low NOx Burner and Selective Noncatalytic Reduction	80	$5,649 for NOx<1 tpd and $4,157 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and selective non-catalytic reduction (SNCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to natural gasfi-red dand process gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBNPHNG and NLNBNPHPG
Process Heaters - Natural Gas or Process Gas	Selective Non-Catalytic Reduction	60	$4,574 for NOx<1 tpd and $3,130 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas-fired and process gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRPHNG and NSNCRPHPG
Process Heaters - Natural Gas or Process Gas	Ultra-Low NOx Burner	75	$2,407 for NOx<1 tpd and $1,926 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of ultra-low NOx burner (ULNB) add-on technologies to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas-fired and process gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NULNBPHNG and NULNBPHPG
Process Heaters - Natural Gas, Process Ges or LPG	Low NOx Burner and Flue Gas Recirculation	55	$6,741 for NOx<1 tpd and $5,136 for NOx>1 tpd		72, 169, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired process heaters, process gas- fired and LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFPHNG, NLNBFPHPG, and NLNBFPHLG
Process Heaters - Other Fuel	Low NOx Burner and Selective Catalytic Reduction	91	$8,699 for NOx<1 tpd and $5,072 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to other (not classified) fuel-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHOF
Process Heaters - Process Gas	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFFPHP
Process Heaters - Process Gas or Natural Gas or LPG	Selective Catalytic Reduction	75	$19,324 for NOx<1 tpd and $13,096 for NOx>1 tpd		72, 172, 175, 179, 186, 224	This control is the selective catalytic reduction (SCR) of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperature. This control applies to natural gas-fired, process gas-fired, or LPG-fired process heaters with NOx emissions greater than 10 tons per year.	NSCRPHNG, NSCRPHPG, and NSCRPHLP
Process Heaters - Residual Oil	Low NOx Burner and Selective Catalytic Reduction	90	$6,316		72, 167, 172, 175, 179, 186, 224	This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to residual oil-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBSPHRO
Process Heaters - Residual Oil or Other Fuel	Low NOx Burner	37	$4,045 for NOx<1 tpd and $1,140 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to Residual Oil process heaters and process heaters reporting "Other" for fuel use.	NLNBUROGN, NLNBUPHOF, and NLNBUPHRO

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Process Heaters - Residual Oil or Other Fuel	Low NOx Burner and Flue Gas Recirculation	34	$5,601 for NOx<1 tpd and $2,215 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control applies to Residual Oil process heaters and process heaters reporting "Other" for fuel use.	NLNBFPHRO and NLNBFPHOF
Process Heaters - Residual Oil or Other Fuel	Selective Catalytic Reduction	75	$8,587 for NOx<1 tpd and $5,762 for NOx>1 tpd		72, 172, 175, 179, 186, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). Tha SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to residual oil fired process heaters and process heaters with unclassified fuels with NOx emissions greater than 10 tons per year.	NSCRPHRO and NSCRPHOF
Process Heaters - Residual Oil or Other Fuel	Selective Non-Catalytic Reduction	60	$3,098 for NOx<1 tpd and $1,765 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to residual oil-fired process heaters and process heaters with unclassified fuel use with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRPHRO and NSNCRPHOF
Process Heaters - Residual Oil or Other Fuel	Ultra-Low NOx Burner	73	$2,070 for NOx<1 tpd and $578 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of ultra-low NOx burner (ULNB) add-on technologies to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to residual oil-fired process heaters and process heaters with unclassified fuels with uncontrolled NOx emissions greater than 10 tons per year.	NULNBPHRO and NULNBPHOF
Pulp and Paper - Natural Gas - Incinerators	Selective Catalytic Reduction	90	$3,748		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas incinerators at pulp and paper plants.	NDSCRPPNG
Reciprocating Internal Combustion Engines - Oil	Ignition Retard	25	$928		72, 169	This control is the use of ignition retard technologies to reduce NOx emissions. This applies to oil IC engines with uncontrolled NOx emissions greater than 10 tons per year.	NIRRICOIL
Reciprocating Internal Combustion Engines - Oil	Selective Catalytic Reduction	80	$1,615		106	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to oil-fired IC engines with uncontrolled NOx emissions greater than 10 tons per year.	NSCRRICOIL
Rich Burn Internal Combustion Engines - Gas/ Diesel/ LPG	Non-Selective Catalytic Reduction	90	$412	VOC - 50%, CO - 90%	72, 73, 106, 199, 236, 237	This control is the application of Non-Selective Catalytic Reduction (NSCR) to reduce NOx emissions. NSCR is achieved by placing a catalyst in the exhaust stream of the engine. The exhaust passes over the catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20. NSCR is also referred to as three-way catalyst because it simultaneously reduces NOx, CO, and HC to water, CO2, and N2. This control applies to Gas-fired, Diesel-fired, and LPG-fired Rich Burn Internal Combustion Engines.	NNSCRRBGD and NNSCRRBIC
Rich Burn Internal Combustion Engines - Natural Gas	Non-Selective Catalytic Reduction	90	$628	VOC - 50%, CO - 90%	72, 73, 106, 199, 236, 237	NSCR is achieved by placing a catalyst in the exhaust stream of the engine. The exhaust passes over the catalyst, usually a noble metal (platinum, rhodium or palladium) which reduces the reactants to N2, CO2 and H20 (NJDEP, 2003). Typical exhaust temperatures for effective removal of NOx are 800-1200 degrees Fahrenheit. An oxidation catalyst using additional air can he installed downstream of the NSCR catalyst for additional CO and VOC control. This includes 4-cycle naturally aspirated engines and some 4-cycle turbocharged engines. Engines operating with NSCR require air/fuel control to maintain high reduction effectiveness.	NNSCRRBIC2
Sand/ Gravel - Dryer	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to sand and gravel drying processes with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSGDR
Secondary Aluminum Production - Smelting Furnace/ Reverberatory	Low NOx Burner	50	$915		72, 172, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to secondary aluminum production operations with smelting furnaces and uncontrolled NOx emissions greater than 10 tons per year.	NLNBSASF
Solid Waste Disposal Government - Other Incinineration - Sludge	Selective Catalytic Reduction	90	$3,748		167	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to solid waste disposal operations with uncontrolled NOx emissions greater than 10 tons per year.	NDSCRSWIN

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Space Heaters - Distillate Oil	Low NOx Burner	50	$1,894 for NOx<1 tpd and $3,322 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to distillate oil-fired space heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUSHDO
Space Heaters - Distillate Oil	Low NOx Burner and Flue Gas Recirculation	60	$4,012 for NOx<1 tpd and $1,220 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSHDO
Space Heaters - Distillate Oil	Selective Catalytic Reduction	80	$4,462 for NOx<1 tpd and $2,423 for NOx>1 tpd		72, 172, 175, 179, 185, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to distillate oil-fired space heaters with NOx emissions greater than 10 tons per year.	NSCRSHDO
Space Heaters - Distillate Oil	Selective Non-Catalytic Reduction	50	$7,447 for NOx<1 tpd and $3,033 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to distillate oil-fired space heaters with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRSHDO
Space Heaters - Natural Gas	Low NOx Burner	50	$1,316 for NOx<1 tpd and $1,043 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired space heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUSHNG
Space Heaters - Natural Gas	Low NOx Burner and Flue Gas Recirculation	60	$4,253 for NOx<1 tpd and $947 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to LPG-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSHNG
Space Heaters - Natural Gas	Oxygen Trim and Water Injection	65	$1,091 for NOx<1 tpd and $514 for NOx>1 tpd		72, 172, 175, 179, 104, 185	This control is the use of Oxygen Trim and Water Injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to natural gas-fired space heaters with uncontrolled NOx emissions greater than 10 tons per year.	NOTWISHNG
Space Heaters - Natural Gas	Selective Catalytic Reduction	80	$4,590 for NOx<1 tpd and $1,942 for NOx>1 tpd		72, 172, 175, 179, 185, 224	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to natural gas fired space heaters with NOx emissions greater than 10 tons per year.	NSCRSHNG
Space Heaters - Natural Gas	Selective Non-Catalytic Reduction	50	$6,211 for NOx<1 tpd and $2,520 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to natural gas fired space heaters with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRSHNG
Starch Manufacturing - Combined Operations	Low NOx Burner and Flue Gas Recirculation	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to starch manufacturing with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSMCO
Steel Foundries - Heat Treating Furnaces	Low NOx Burner	50	$915		72, 175, 179, 181	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to heat treating operations at steel foundries with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUSFHT
Steel Production - Soaking Pits	Low NOx Burner and Flue Gas Recirculation	60	$1,204		72, 175, 179, 181	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to soaking pits at steel production operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSPSP
Sulfate Pulping - Recovery Furnaces	Low NOx Burner	50	$1,316 for NOx<1 tpd and $1,043 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to recovery furnaces at sulfate pulping operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUSPRF

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Sulfate Pulping - Recovery Furnaces	Low NOx Burner and Flue Gas Recirculation	60	$4,109 for NOx<1 tpd and $947 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to residual oil-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.	NLNBFSPRF
Sulfate Pulping - Recovery Furnaces	Oxygen Trim and Water Injection	65	$1,091 for NOx<1 tpd and $514 for NOx>1 tpd		72, 172, 175, 179, 184, 185	This control is the use of Oxygen Trim and Water Injection to reduce NOx emissions. Water is injected into the gas turbine, reducing the temperatures in the NOx-forming regions. The water can be injected into the fuel, the combustion air or directly into the combustion chamber. This control applies to recovery furnaces involved in sulfate pulping operations with uncontrolled NOx emissions greater than 10 tons per year.	NOTWISPRF
Sulfate Pulping - Recovery Furnaces	Selective Catalytic Reduction	80	$2,761		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to recovery furnaces in sulfate pulping operations with NOx emissions greater than 10 tons per year.	NDSCRSPRF
Sulfate Pulping - Recovery Furnaces	Selective Catalytic Reduction	90	$2,852		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to recovery furnaces in sulfate pulping operations with NOx emissions greater than 10 tons per year.	NDSCRSPRF
Sulfate Pulping - Recovery Furnaces	Selective Non-Catalytic Reduction	50	$6,211 for NOx<1 tpd and $2,520 for NOx>1 tpd		72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to sulfate pulping operations with recovery furnaces and uncontrolled NOx emissions greater than 10 tons per year.	NSNCRSPRF
Surface Coating Operations - Coating Oven Heater -Natural Gas	Low NOx Burner	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd		72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to natural gas-fired coating oven heater at surface coating operations with uncontrolled NOx emissions greater than 10 tons per year.	NLNBUCHNG
Taconite Iron Ore Processing - Induration - Coal or Gas	Selective Catalytic Reduction	90	$6,351		167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal or gas induration in taconite iron ore processing.	NDSCRFEP
Textile-Type Fiberglass Manufacturing - Recuperative Furnace	Low NOx Burner	40	$2,712		72, 175, 179, 182	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zona and reducing the amount of oxygen available in another. This control is applicable to textile-type fiberglass manufacturing operations with gas- or oil-fired recuperative furnaces and uncontrolled NOx emissions greater than 10 tons per year.	NLNBUFMTF
Waste Incineration - Municipal Waste Combustors or Solid Waste Disposal - Sludge Incinerators (Government)	Selective Non-Catalytic Reduction	45	$1,814		72, 172, 175, 179, 202	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chamical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to municipal waste combustors and government solid waste disposal sludge incineration sources with uncontrolled NOx emissions greater than 10 tons per year.	NSNCRMWCB and NSNCRSWIN
Agricultural Burning	Seasonal Ban (Ozone Season Daily Only)	100	$0		72, 73, 133	An ozone season ban of burning is a ban of burning on an ozone season day where ozone exceedances are predicted. Ozone season daily ban of agricultural burning to reduce NOx emissions during the ban.This control is applicable to field burning where the entire field would be set on fire, and can be applied to all crop types.	NEPABURN96
Commercial/ Institutional - Natural Gas	Water heater replacement	45	$0		72, 73, 113, 132, 133	This control would replace existing water heaters with new water heaters. New water heaters would be required to emit less than or equal to 40 ng NOx per Joule heat output. This control applies to all commercial/institutional natural gas burning water heaters.	NWHCMNGC99
Commercial/ Institutional and Residential Water Heaters or Space Heaters - Natural Gas	Water heater + Low NOx Burner Space heaters	44	$1,974		72, 73, 133, 148	The South Coast and Bay Area AQMDs set emission limits for water heaters and space heaters. This control is based on the installation of low-NOx space heaters and water heaters in residential, commercial and institutional sources for the reduction of NOx emissions.	NWLCMNGC99 and NWLRSNGC99
Industrial Coal Combustion	RACT to 25 tpy (Low NOx Burner)	21	$2,167		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by coal that emit over 25 tpy NOx.	NR25COL96
Industrial Coal Combustion	RACT to 50 tpy (Low NOx Burner)	21	$2,167		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by coal that emit over 50 tpy NOx.	NR50COL96
Industrial Natural Gas Combustion	RACT to 25 tpy (Low NOx Burner)	31	$1,236		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by netural gas that emit over 50 tpy NOx.	NR25NGC96
Industrial Natural Gas Combustion	RACT to 50 tpy (Low NOx Burner)	31	$1,236		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by natural gas that emit over 50 tpy NOx.	NR50NGC96
Industrial Oil Combustion	RACT to 25 tpy (Low NOx Burner)	36	$1,894		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by oil that emit over 25 tpy NOx.	NR25OIL96

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Source Category	Emission Reduction Measure Name	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	Other pollutants controlled	Reference for More Information	Description/Notes/Caveats	CoST Control Abbreviation
Industrial Oil Combustion	RACT to 50 tpy (Low NOx Burner)	36	$1,894		72, 73, 137, 132	The RACT control technology used is the addition of a low NOx burner to reduce NOx emissions. This standard applies to sources with boilers fueled by oil that emit over 50 tpy NOx.	NR50OIL96
Open Burning	Episodic Ban (Daily Only)	100	$0		72, 73, 133, 132	This is a generic control measure that would ban open burning on days where ozone exceedances were predicted, reducing NOx emissions on those days. This measure would not reduce the annual emissions.	NEPOBRUN96
Residential and Commercial/ Institutional - Natural Gas-Fired Water Heaters or Space Heaters	Low NOx Burner (1997 AQMD)	75	$955		72	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. The South Coast and Bay Area AQMDs set emission limits for water heaters and space heaters. This control is based on the installation of low-NOx space heaters and water heaters in residential and commercial/institutional sources.	NLNCMNGC03 and NLNRSNGC03
Residential Natural Gas	Water heater replacement	45	$0		72, 73, 113, 132, 133	This control would replace existing water heaters with new water heaters. New water heaters would be required to emit less than or equal to 40 ng NOx per Joule heat output. This control applies to all residential naturel gas burning water heaters.	NWHRSNGC99
Water Heater, Space Heater - Natural Gas	Low NOx Burner	7	$928		73	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another.	NLNBSPWHNG
Process Heaters - Distillate Oil, Residual Oil, or Other Fuel	Low NOx Burner and Selective Noncatalytic Reduction	75	$3,891 for NOx<1 tpd and $1,990 for NOx>1 tpd		72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and selective non-catalytic reduction (SNCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control is applicable to process heaters fired with distillate, residual oil, and other unclassified fuels.	NLNBNPHRO and NLNBNPHOF

Senator CARPER. Thank you very much for your comments, especially that last paragraph.

Ms. MCCARTHY. I appreciate that. Maybe I should have started with that one.

[Laughter.]

Senator CARPER. Senator Alexander is not here. He and I were together earlier this morning. He is in a markup. I think he is the only Republican at the markup; he needs to be there. He is submitting a statement for the record. But this is something he and I worked on very closely, as I have with my colleagues to my right over the years. So this is a shared effort on our side. We are really pleased with what you just said.

[The prepared statement of Senator Alexander follows:]

STATEMENT OF HON. LAMAR ALEXANDER, U.S. SENATOR FROM THE STATE OF TENNESSEE

I am pleased that the Committee is holding this hearing today on an issue that I believe is of great importance. I see no reason why we cannot continue to improve on the significant reductions in harmful pollutant emissions from our coal-fired power plants. The EPA's efforts to improve air quality by reducing power plant emissions of SO_2 and NO_x are a positive step, but they are too regional, too complicated, and too weak to be a permanent solution for public health and for the certainty and flexibility that utilities need to keep electric rates down.

While I applaud the fact that the EPA's Transport Rule requires greater reductions than under the previous Clean Air Interstate Rule, I am concerned about several things in the proposed rule.

First, this rule will not address the issue of mercury. While I know that the EPA intends to propose a rule on mercury reductions in the future, the patchwork of regulations coming out of the agency reduces the certainty for electric utilities and their customers. It would be more efficient to discuss these proposals simultaneously so that we could better understand their interaction as well as the ultimate costs and benefits.

Second, I am concerned that this rule will wipe out allowances that have been traded or purchased among the various regulated utilities, opening up the EPA to lawsuits for taking assets. Already we have seen the allowance values plummet in the SO_2 and NO_x markets.

Next, I am concerned that the EPA's preference to only allow intrastate trading of allowances will increase the costs to customers. One needs to look no further than the home States of our colleagues on this Committee to see this disparity. Senator Voinovich's State of Ohio will end up with allowance costs far greater than those of Senator Sanders' utilities in Vermont. If these allowances were able to be traded across State lines we could see the evolution of a more efficient market and lower costs overall.

I am also fearful that the EPA's rule will face legal challenges on the basis that it may not be in compliance with the 2008 ruling reinstating the Clean Air Interstate Rule. The continued legal and regulatory back and forth has resulted in a very uncertain regulatory environment for our Nation's electricity providers, and it is time to move forward on a path to certainty.

My concerns lead me to believe that this EPA action is even more reason for Congress to pass the Carper-Alexander legislation that would establish a national program with stronger permanent reductions in SO_2 and NO_x emissions and eliminate 90 percent of mercury emissions.

The bipartisan Clean Air Act Amendments of 2010 is cosponsored by 6 Republicans, 8 Democrats, and an Independent Senator. We have worked hard to provide a program that is nationwide, provides strong targets for emission reductions, and establishes an allowance and trading system that keeps costs down.

The legislation puts strict limits on three noxious emissions—sulfur dioxide, nitrogen oxide, and mercury—that are produced when we burn the coal which provides 50 percent of our Nation's electricity. These pollutants affect the health of millions of Americans. The Environmental Protection Agency (EPA) estimates that 24,000 premature deaths a year from lung diseases are caused by coal pollution. Forty-eight States have issued fish consumption advisories due to mercury pollution, covering 14 million acres of lakes, 882,000 river miles, and the coastal waters of 13 entire States.

Our legislation will also direct the EPA, for the first time, to reduce mercury emissions by at least 90 percent no later than 2015. By 2018 our bill will cut SO_2 emissions by 80 percent from current levels and by 2015 will cut NO_x emissions by 53 percent from current levels. That should save more than 215,000 lives and more than $2 trillion in health care costs by 2025 according to EPA's analysis. It will combine stronger national standards on these two pollutants with existing emissions trading systems so the market will determine the cheapest way to reduce emissions. The original trading system imposed on sulfur emissions in 1990 has cut emissions in half while the real cost of electricity at the same time decreased. The first estimates of the cost of our bill by the EPA and a recent study on mercury control technologies by the General Accounting Office show that the new standards in our bill will equal an increase of about $2–$3 per month on the average Tennessean's utility bill.

I fear that the EPA's Transport Rule and an expected EPA rule on Hazardous Air Pollutants such as mercury will be more expensive for the country and yield more modest emissions reductions than our bill.

As has already been stated this rule is over 1,000 pages, and we are just beginning to understand it. I look forward to learning more from our witnesses today regarding the costs and benefits of this proposed rule and will focus my questions on a comparison with the bipartisan legislation authored by Senator Carper, me, and 14 other cosponsors.

Senator Carper and I have introduced clean air legislation every session I have been a Senator. We have a better chance to succeed this year because of stronger bipartisan support, more public understanding of the dangers of emissions, and improved technology for controlling these pollutants. Bipartisan support for the Clean Air Act Amendments shows that when it comes to air pollution we can find a way forward, and the American people will all be better for it.

Senator CARPER. We will have two rounds of questions, 5 minutes each. I want to go back, the first question, just to go back to a point raised by Senator Voinovich. I think it is one of the most important issues that we are going to discuss today.

On page 2 of your testimony you talk about how the proposed Transport Rule would prevent 14,000 to 36,000 premature deaths annually. And you suggest that the health and welfare benefits could be quantified. And you put a range on it, $120 billion to $290 billion annually. That is annually in 2014.

Ms. MCCARTHY. That is correct.

Senator CARPER. And you go on to say that the benefits will far outweigh the estimated annual cost of $2.8 billion. I want my colleagues—and I am going to ask Senator Voinovich, I am just going to ask you if you could just bear with me here on this one point. You raised the issue of cost-benefit; great question. It is one that we have to be focused on. And in the testimony that we have heard, in the year 2014 the range of the benefits anywhere from $120 billion forecast to as much as $290 billion.

Let's take the low end of that range. Let's say it is not even the mid-range. Let's say that it is $120 billion. It is not $290 billion, it is $120 billion, the low end of the range. The costs that were projected were for the $2.8 billion. Let's say that is low. Let's say it is actually $3 billion.

And what I want you to do is sort of using that information, talk to us about the cost-benefit of doing this. We are not interested in doing something, or taking an approach where the costs just are out of sight and really inconsistent with the benefit. Just talk to us about why this is important.

Is it just 1 year? Do the numbers—going forward, do the numbers get worse in terms of the cost-benefit? Or do they get more favorable? Share with us. This is an important point.

Ms. MCCARTHY. It is an important point. Let me just clarify, to begin with, that the standards that we set under the National Ambient Air Quality Standards are health-based standards. But cost-benefit analysis is always applied in the implementation of those standards. And the Transport Rule is the implementation of a variety of NAAQS standards to try to address upwind contributions.

When we apply cost-benefit analysis what we see here is overwhelming public health benefits. Just to express that a little bit more specifically, we are talking about in 2014 avoiding 14,000 to 36,000 premature deaths, 21,000 cases of acute bronchitis, 23,000 cases of non-fatal heart attacks, 26,000 hospital and emergency room visits. I could go on and on. And those benefits translate into at least $120 billion annually. Those costs begin in 2014, and they continue every year.

To compare that with the cost of this bill, the costs associated with this bill are $2.8 billion. It is not even close. This bill is overwhelmingly beneficial when you do it from traditional cost-benefit analysis. The simple reason for that is that there are very cost effective reductions available to us in the power sector that we should have taken advantage of many years ago. But we have not, and we plan to now. I think this is a reasonable and cost effective approach.

Senator CARPER. Let me follow up with this, if I could.

When you analyze the impacts of this rule, what they might have on fuel use, the impacts on plant closures, the impact on electricity prices, do you see any significant changes over current status in those particular areas, please?

Ms. MCCARTHY. We have looked at all of those issues. What we know is the average electricity prices could increase somewhere less than 2 percent. Our estimate is about 1.5 percent. That would be by 2014, which means if you pay $100 now in your electric bill, you could pay $1.50 more. And our natural gas prices will increase less than 1 percent by 2014. And we don't see significant shifting away from the use of coal, although there will be some shifting to cleaner coal use.

The simple fact is that as we looked at these reductions in detail we not only did a cost-benefit analysis, but we factored costs into decisions in terms of where the most, the highly most cost effective reductions could be achieved. There are many of them in the power sector.

So we have an ability to get highly cost effective reductions there, and they provide tremendous public health benefits without significant impacts to consumers on electricity prices, but significant public health benefits.

Senator CARPER. Good.

My time is expired.

Senator Inhofe.

Senator INHOFE. Thank you, Mr. Chairman.

As I said in my opening statement, Ms. McCarthy, the concern I have, a lot of concerns I have are on uncertainty. Just now I wrote down what you said, and they said that was also in your printed statement. You said, we supply the power industry with a clearer picture as to what to expect over the next 10 years. That is what I would like to achieve. Predictability is the problem.

And I know that we go through this discussion all the time. While I agree with Senator Voinovich in his concern over how we can and how we cannot use cost-benefit analysis, nonetheless there is a cost to this stuff. Anything that we are doing and any level of uncertainty in the power industry is going to be paid for by everybody in this room. We are the ones who are going to have to be absorbing this.

So I would start off by, how do you think the Transport Rule provides certainty to the regulated community? If you could comment to that.

Ms. MCCARTHY. Senator, thank you for asking the question. I share your goal of trying to understand what the rules are that are moving forward and how they could impact the power sector, particularly to ensure that we continue to have a reliable and affordable energy supply.

The best thing that I thought that we could do with this Transport Rule, which is what I think we accomplished, is to make it as legally defensible as we possibly could, to listen to the Court carefully and then to use as much of our technical ability as we could to identify the lowest cost opportunities to achieve the reductions we need not for the emission reductions but for the air quality impacts.

So what you have here is a rule that is legally defensible, that we believe will—even though we expect it to be challenged—will hold up in court. We think it is a smart rule and it is cost effective.

Senator INHOFE. First of all, would one of the staff hold up the chart that Senator Voinovich used there? This chart assumes that there is no litigation. That would have to be added on to all of these timelines that are in there. I am in a kind of position where I would say I don't think it is going to be litigated. I don't think it is. I know it is. This is going to happen. With the Bush administration's CAIR rule, that litigation took almost 3 years to get resolved.

Is there any way that you can guarantee that litigation this time around will be dealt with more expeditiously? We know it is going to happen. But is there anything that you can think of that is going to be different now in terms of the litigation that we know is going to come?

Ms. MCCARTHY. I fully expect that it will be litigated. I think the difference that I am trying to point out is I think it adheres much more closely to the requirements in the Clean Air Act. I think it is much more tied to the ability to achieve the air quality reductions that the Clean Air Act is requiring.

Senator INHOFE. In my State of Oklahoma—it is included among the States in this Transport Rule. It wasn't under the CAIR rule. The EPA apparently included Oklahoma in the summer ozone season due to transport from the Dallas-Fort Worth areas and the impacts from that. The EPA modeling shows that approximately two parts per billion impact from transport on the Dallas-Fort Worth area. Yet your slide show of the Transport Rule indicates that Dallas and Fort Worth will be in attainment with the 1997 ozone NO_x of 80 parts per billion by 2014 even without the Transport Rule.

I have a couple of charts; they are not large enough to use, but they come from the EPA, and you are very familiar with them, showing where we are going to be with and without. So my question is, why would you include Oklahoma in the summer season regime if Dallas-Fort Worth will get into attainment even without the Transport Rule?

Ms. MCCARTHY. My understanding, Senator, is that there are three States that actually were added into the transport region that will be impacted by this rule. Oklahoma is clearly one of them.

If I could just step back, one of the ways in which we had to address the Court's challenge back to us was to very clearly articulate what significant contribution means for an upwind State in terms of the ability for downwind States to both achieve air quality reductions that are required as well as maintain them. My understanding is that for Oklahoma it wasn't a very close call in terms of the ozone level.

Senator INHOFE. You say it was not?

Ms. MCCARTHY. It was not. One percent is what we are using as a threshold for significant contribution. And Oklahoma actually does contribute to the air quality impacts associated with Dallas. So we are asking Oklahoma to pay its fair share and contribute to the relief of that downwind State in that area.

Senator INHOFE. OK, my time has expired, but what are the other two States? You said it impacted three States.

Ms. MCCARTHY. Nebraska and Kansas.

Senator INHOFE. Thank you, Mr. Chairman.

Senator CARPER. Thank you.

Senator Cardin.

Senator CARDIN. Thank you, Mr. Chairman.

In the interest of continuing this bipartisan cooperation, Senator Inhofe, we have blown up that one chart. So if you need it blown up, you can certainly use our copy. Just want you to know we are all working together on this.

But it is the same point; I guess I want to take it from a little bit different angle. I certainly support what EPA is trying to do with these transport rules. I certainly support what Senator Carper is trying to do with congressional authority. And I think certainty is an important issue here. Having clear authority under the Clean Air Act would also, I think, help in certainty.

I come at this, though, from a little bit different angle. That is if the new Clean Air Transport Rules go into effect, and we achieve what we expect to be able to, there still will be gaps, including in my State of Maryland. There will be counties struggling to maintain attainment. Baltimore City, Anne Arundel County just south of Baltimore City are two counties that EPA projects will struggle to maintain air quality attainment.

My point is, what else do we need to do either through the regulatory authorities that EPA currently has or through congressional authority or action? What more do we need to do in order to be able to achieve what science tells us we should achieve to protect the health of the people of our community?

Ms. MCCARTHY. Senator, let me respond first by telling you that I share your interest in making sure that we actually, through these measures, achieve the air quality reductions that the Clean Air Act requires. I think we did our best in this Transport Rule to make it very clear that in the interest of getting the rule out in a timely way and capturing the reductions that we knew were going to be available to us in 2012, that we put out the best rule that we could on the basis of the modeling that we had the time and the technical expertise to run.

What we did find was that on the NO_x reductions there would need to be additional NO_x reductions, clearly, to get into compliance with the 1997 standard because there are two areas, as you say, that still remain in non-attainment, even with these reductions.

But we also acknowledge that we are working very hard at updating an ozone standard. As a result we have made a commitment that we will look at additional NO_x reductions when we see a NAAQS standard is being revised. Because too often when the NAAQS standards have been revised we have put considerable pressure on each State to develop plans for attainment, but we haven't put commensurate pressure on the upwind States to contribute to that attainment challenge. And this is a model to be able to do that. And it is a clear commitment from EPA that we are going to also seek additional NO_x reductions. We wish we had been able to do more with this rule.

But given the time constraints that we had what we best did was achieve the reductions we thought we could as quickly as we could and put the challenges out there. We have asked for comments on how we could do better with these rules. We have asked for comments on the structure of the rule. And we have made a commitment that we need to do more; we know we need to do more, and we will.

Senator CARDIN. And I support your response. It is clear to me that you do have that authority under the Clean Air Act to take additional steps provided you follow the process that the Court has indicated needs to be followed. And you have the documentation to demonstrate the results that can be obtained.

I know that Senator Carper in his efforts wants to make sure that although we give you clear guidance and we have some predictability we don't want to undermine the authority of EPA to act under the authority under the Clean Air Act itself. I will welcome your thoughts as we go through this legislative process, particularly as it relates to NO_x, that yes, we want to make legislative progress here, but we don't want to undermine your authority to do what you are required to do currently under the Clean Air Act.

Ms. MCCARTHY. Thank you, Senator. I guess the big challenge for us is that emissions reductions are welcome when they are cost effective. But the real challenge for us is the ultimate air quality that we are actually producing for the American people.

Senator CARDIN. Absolutely. I agree with Senator Voinovich. This is clearly, I think it is required by the courts anyway. But it is certainly a part of the process here.

Thank you, Mr. Chairman.

Senator CARPER. Thank you, Senator Cardin.

Senator Voinovich.

Senator VOINOVICH. Thank you.

Mr. Korleski is going to be testifying in the next panel, but I would like to get your reaction to a paragraph in his testimony. "Next, we are concerned with the concept that each time USEPA promulgates a new, more restrictive air quality standard, USEPA intends to revise the Interstate Transport Rule by changing the emission budgets."

We have two main concerns with this approach. First, we expect that at some point it will be difficult or impossible to develop and implement technology that can achieve the new, more restrictive budgets. Second, the regulated community must have some degree of certainty to timely plan investments and controls, fuels and operations at generating facilities in order to achieve necessary emission levels by the relevant deadline. We would recommend that anything USEPA promulgates for an emission sector would not change for at least 10 years, and then only if USEPA demonstrates that additional controls are technically achievable and cost effective.

How do you respond to what Mr. Korleski says here in his testimony?

Ms. McCarthy. First of all, Senator, I would like to tell you that the next panel is represented by four close colleagues of mine, one of which is Chris Korleski. I respect his judgment tremendously. We are close colleagues.

What I would suggest to you is that what we are doing in the Transport Rule is I believe doing what the courts tell us we must do under the Clean Air Act and what we believe we must do under the Clean Air Act. I think Mr. Korleski is providing you with his understanding of what he believes would be a better approach to that. But what we do in the Clean Air Act is on a 5-year basis where we are obligated to look at the National Ambient Air Quality Standards, identify those standards, and then if reductions are necessary to achieve those, we are required to implement them.

I don't believe that the addition of the Transport Rule, which is really an obligation to address the upwind States' contributions, would do anything but fill in what has been a gap in the system in terms of how we have implemented the Clean Air Act. But Mr. Korleski is clearly sending Congress a signal that he would prefer a different approach.

Senator Voinovich. I think we would recommend any budget USEPA promulgates for an emissions sector would not change for at least 10 years, and then only if USEPA demonstrates that additional controls are technically achievable and cost effective. I think that gets at the whole issue of this business of uncertainty about where are we going.

Ms. McCarthy. The only thing I would clarify, Senator, is that EPA has made a commitment to using this model that we are proposing, when it is finalized, and that it is a good model to get at upwind contribution. Not every NAAQS might require that. But we are obligated to take a look at it.

And the last issue I would indicate is that over the 40 years of the Clean Air Act I think one of its major values has been that it has not waited for technologies to be available to achieve required air quality reductions but has driven those technologies forward. The Clean Air Act has really pushed the envelope in terms of developing new technologies that are now readily available, that now offer cost effective opportunities. Those are very technologies we are looking to take advantage of in this Transport Rule.

Senator VOINOVICH. That is interesting, and I don't have the history of it, but I am going to look into it. When AEP put on a scrubber in 1992 or 1993, when I was Governor, at a cost of $650 million, the technology was there for them to do that. That is one of the big hang ups I have with EPA and many other people, is that the technology—for example, for greenhouse gas emissions—is not available today, not commercially deployable. If you are going to ask somebody to meet a standard, the technology ought to be there. What happened was, it was, and you guys mandated that it take place.

But it wasn't, for example, you are talking about some new rulemaking based on MACT rulemaking. One of the things that we are all concerned about here is that we have the feeling that EPA is going to go in and look at other pollutants as it moves forward. The issue is, are they going to study whether or not these things really are making a difference, and are they going to have alternative control strategies, or are they just going to come down and say, here it is, and you do it. We run into this almost everywhere we go. It is, well, we have these MACT standards, back with the Water Act. They mandated MACT standards, and all hell broke loose in the country.

Then we came back, and we amended the Water Act to say that if the technology that you have is getting the job done, that is fine. But the EPA said, they originally said no, you have to do this other. And in many instances, what they asked them to do was more expensive than the property values in the town that they were asking them to do it. It is a reasonableness thing that comes into play here.

Ms. MCCARTHY. I appreciate that, Senator. I know there is a lot of concern in particular about the utility MACT standard which we are planning to propose under a court timeline next spring. But I will assure you that the MACT standards are based on already available and in-use technologies. There is a very serious requirement to look at costs associated with that. So we will do our best to balance as the Clean Air Act requires and that you are seeking.

Senator CARPER. All right, Senator Voinovich. There will be another round for 5 minutes of questions.

Let me kick off that second round, Ms. McCarthy, by following up on some comments and questions from Senator Cardin. When you state that the EPA plans to move forward on an additional Transport Rule next year to help States meet the new ozone standards that will be finalized, I think, in August, are you saying that EPA will be looking to tighten the seasonal ozone cap, the seasonal ozone cap and not the annual NO_x cap?

Ms. MCCARTHY. That is correct, Senator.

Senator CARPER. Thank you.

In your statement, you mention that there will be limited trading allowed under the Transport Rule. If a utility has any banked sulfur dioxide or nitrogen oxide credits from the old CAIR program or from the acid rain program, can they be used under this new system that you have envisioned?

Ms. MCCARTHY. The Court was pretty clear to us, Mr. Chairman, that the title IV SO_2 allowances associated with the acid rain program cannot be used as currency to achieve compliance with the

Transport Rule. Concerning the CAIR NO_x allowances, our proposal is that those allowances also not be used as currency in this program, but we are taking comment on that. The main concern with that was making sure that there was no legal vulnerability in the rule. Those allowances benefited by the fuel adjustment factor. They were based on the fuel adjustment factor. That was determined to not be legally defensible by the Court.

So we felt that the most appropriate decision to make was to listen to the Court and to abide by that as closely as we could.

Senator CARPER. You talked earlier in your opening statement about trying to find a way for regulation to work with legislation. Is that an area where perhaps that could be brought to bear?

Ms. MCCARTHY. I believe that the legislation that you have proposed and the way in which you have proposed does leave us considerable opportunity to marry those two to the benefit of the American public.

Senator CARPER. Just a follow-on. Are you worried about utilities increasing their emissions before 2012, emitting their bank, if you will, because the banks aren't worth anything? Is that a concern that you might have?

Ms. MCCARTHY. Could you repeat the question?

Senator CARPER. Yes. Are you worried about the utilities increasing their emissions before 2012, sort of emitting their bank, if you will, because the banks aren't worth much of anything?

Ms. MCCARTHY. Yes. We have been watching that very closely. We are not seeing that that has been the trend. One of the reasons why we felt it was pretty important to get a rule out quickly was so that it wouldn't allow backsliding. That is basically one of the considerations, was our 2012 targets in this rule are very much about making sure that we take advantage of the technologies that have been put in place as a result of CAIR phase one and that those technologies be run as much as they can so we can take advantage of those inexpensive reductions.

Senator CARPER. You may have responded to this question, but I want you to do it again, if you have. Will companies or will utilities be able to bank emissions in the future?

Ms. MCCARTHY. Yes.

Senator CARPER. OK, thanks. Those were my questions.

Senator Inhofe.

Senator INHOFE. I just have, for clarification on the issue that I brought up, it appears to me, and as I am looking at this chart, as to what is going to happen without the proposed Transport Rule, you are familiar with this chart, that the Dallas-Fort Worth area will come into compliance with the 1997 ozone NAAQS without the significant contribution you referred to of Oklahoma and you are requiring with this Transport Rule.

Now, at least according to the chart, why would we go, why would you be listing Oklahoma, or counties in Oklahoma, if they are going to be in compliance without the rule? I don't understand that.

Ms. MCCARTHY. Senator, I apologize if I don't have all the information that I need to provide you the best answers. But let me give you my understanding. That is that the courts told us one of the deficiencies of CAIR was that it first of all didn't look at contribution as well as it needed to State by State. But it also didn't look at the issue of maintenance. Because there are two obligations of upwind States. One is that you don't contribute to non-attainment, and second that you don't make it more difficult for a downwind State to maintain their attainment.

My understanding is that in an effort to respond to the courts we established a significance threshold for both States that contribute to non-attainment and to address this maintenance issue. My understanding is that the State of Oklahoma does have an impact downwind in the Dallas area because it makes it more difficult for that area to maintain compliance with the NAAQS even if it is currently in attainment.

Senator INHOFE. OK, now explain to me how this happens, then. I am not familiar with your modeling. You have come to some conclusions that I sit here and I wonder. We are talking about ozone; we are talking about the summertime. And where we have nothing but south winds. How does Oklahoma make this contribution?

Ms. MCCARTHY. Senator, again, I'll be happy to sit down and our technical staff can walk through it. But our air quality modeling looks fully at all meteorological data. And it is very sophisticated. In the effort to do the work we needed to do for the courts to both identify contributions for non-attainment and for maintenance, we actually looked unit by unit at every power plant in the country. We looked at what obligations they had, what State obligations they had. We identified where we thought the reductions needed to be achieved upwind so that States could just look at their in-State compliance requirements and we could take care of some of those upwind challenges that they were facing.

In your area, my understanding is that in looking at that in detail, that Oklahoma units would challenge Dallas in terms of their ability to maintain compliance because of emissions that were being generated there that would be contributing to——

Senator INHOFE. In Oklahoma?

Ms. MCCARTHY [continuing]. Dallas, to the Dallas area.

Senator INHOFE. I am seeing behind you, you are flanked by a lot of people who I am sure know a lot more about this than I do. But when I am asked that question, I go back to the State of Oklahoma. What I would like to get from you is, for the record, is something that I can look at and analyze, see if I agree with it, and if not, call you up, and then something that I can pass on and explain. Because right now I am not able to do that.

So if we could do that, and let us kind of get into the weeds on this thing, that would be helpful.

Ms. MCCARTHY. I think that would be great. One of the reasons why we have a good comment period on this is that I am sure other States are going to have similar questions. We certainly want to know that we have done the right technical modeling to make the right decisions.

Senator INHOFE. That is fair enough. Thank you.

Senator CARPER. Thank you.

Senator Voinovich.

Senator VOINOVICH. One of the things that I am doing is we are negotiating with Senator Carper right now on this legislation. And trying to see just what all the facts are. But I am going to read you from this paper that was done by American Electric Power. Assuming the proposed rule goes final a little less than a year from now, i.e., EPA's current schedule is spring of 2011, phase one of the program would allow only a little more than 6 months in total to implement the new emission budgets, establish emission trading programs, and for companies to make the needed investments to comply with these limits. Six months, let alone a year or 2, is not nearly enough time for this.

Having a brand new emission cap, State budgets and allowance allocations in 2012 creates major logistical challenges for the electric power sector and for the States that must implement the programs. Companies will not have sufficient time to design, permit, fabricate, and install emissions controls that may be necessary for meeting the new reduction requirements.

Moreover, additional time is necessary to coordinate installation of major pollution control equipment during spring and fall outage schedules to ensure reliability of the entire utility system. While the EPA claims that phase one will require little investment in the way of new controls, its assumption is predicated upon high level modeling and not the actual physical, contractual, and financial constraints at these facilities during such a short timeframe.

We are talking now about numbers, NO_x, SO_x, mercury, and if you are going to take the numbers and agree to them, then it seems to me that you need to talk about implementation of how long it is going to take for this to be put in place. What is your reaction to what they have suggested here in terms of this Transport Rule and the timing needed to get the job done?

Ms. MCCARTHY. Senator, I think we need to look at the comments when they come in to the Rule. So I appreciate that people could differ in terms of whether or not they think the timing is too tight. But my understanding is that the reductions we are looking to achieve in 2012 are primarily based on running the equipment that has already been invested in and that we believe will be installed and in place as a result of phase one of CAIR.

So we really were looking at 2012 as locking in the investment that have already been made and should be in place and 2014 as a second opportunity to achieve some additional SO_2 reductions, which will require investments. But that time line should provide an opportunity for those investments to be fully made and for companies to be able to comply.

We did also in the rule indicate that we would love to have States come in to us and indicate how they would like the State allocation to be made, which gives an opportunity for a closer look, unit by unit, at where these investments have been made and what kind of reductions can be expected. We do allow a little bit of in-State trading as well. So there is an opportunity there.

And I guess the last issue, Senator, is if any facility believes that they are in good faith trying to comply as best they can and cannot achieve that compliance, there are always opportunities for us to enter into consent agreements that will acknowledge real barriers that they may be facing, and take care of it in that way.

Senator VOINOVICH. I have been watching the face of Mr. Korleski during your testimony. Mr. Korleski, you have listened to that, and I am expecting you when you come up to respond.

Ms. MCCARTHY. I am sure he will be as nice to me as I was to him.

[Laughter.]

Senator VOINOVICH. You are both good friends, but there seems to be some difference of opinion. I know for example, EPA has assumed that AEP will have scrubbed its 585-megawatt Muskingum River Unit No. 5 in Ohio by January 1st, 2011, or only 6 months from now. However, while preliminary engineering was begun several years ago there is no ongoing construction activity associated with this retrofit project.

Even with engineering and construction recommended today, the actual in-service date for the scrubber would still be at least 3 years from now. As such, the EPA assumption that this unit would be scrubbed by 2011 is completely infeasible and inaccurate. That is what they have to say about it.

So there is some real difference of opinion here about how fast the technology is, how much it will cost, how much time it is going to take. It seems to me if we work something out there is going to have to be some compromise on both sides in terms of the numbers, as to the reduction in emissions and also the timeline that you put in to get it done. Or, the alternative is, let's just keep what we have been doing for the last 12 years: lawsuits, delays, what the ambient air standards in 1997 just finally went in. There has to be some kind of meeting of the minds if we expect to get it done.

My experience has been over the years—we could have done a 3-P bill 6 years ago. But the environmental groups, they wanted four Ps. If you don't have four Ps, we won't go with three Ps. The Adirondack Council comes along and says—and Senator Clinton was there at the time—hey, let's do the three Ps. We can get started reducing NO_x, SO_x, mercury. It will help us in the Adirondacks, the Smoky Mountain people came in and said, hey, that is going to help us. Oh, no, we didn't get it done. So we just meandered down the stream, lawsuit after lawsuit after lawsuit. It is not good for anybody.

But the real issue is——

Senator INHOFE. Only the attorneys.

Senator VOINOVICH. Oh, yes, the attorneys make a lot of money, sure. But anyhow, the point is that these are some practical things that I think we have to deal with if we expect to get some kind of meeting of the minds. I won't be happy, maybe Senator Carper, you may not be happy. Utilities won't be happy. But I think it is worth it to try and get it done.

Senator CARPER. Thank you very much. That is a good note to end on. We have a lot at stake here. I think there is good will on all sides. Let's make as much progress as we can.

I appreciate the spirit that I think everybody's participated in today. Thank you so much for coming today. Thank you not just for your testimony but for the work that has taken place to led up to this day as we try to find a way where regulation and legislation can lead to the kind of cost effective results that we all want.

Senators will have 2 weeks to submit questions to you in writing. We ask that you respond as promptly as you can so we can publish our hearing in a timely manner. With that having been said, you are excused. Again, thank you so much for joining us.

Ms. MCCARTHY. Thank you so much, Mr. Chairman.

Senator CARPER. And I would invite our second panel to come forward. While they are coming forward, I am looking at the clock up here. As much as I would like to ask the President to wait until I get there to sign this legislation, he is probably not going to be inclined to do that. They are going to kick off the signing ceremony about 11:25. And we are not going to have a police escort going to the White House. So we will have to move along here smartly. I am anxious to hear the testimony of each of our witnesses.

I am going to go ahead and start the introductions, if I could. First of all, Jared Snyder, Assistant Commissioner of Air Resources, Climate Change and Energy, at the New York State Department of Environmental Conservation. Good morning and welcome. Mr. Chris Korleski, Director of the Ohio Environmental Protection Agency. We have a couple of Buckeyes up here at our side of the table, Senator Voinovich and myself. Whenever we have folks come in from Ohio, I usually start off in introducing them by saying two letters, O-H, and see what they say in response.

Mr. KORLESKI. I-O.

Senator CARPER. That is good. That is good.

Eric Svenson, Vice President of Environmental Health and Safety at PSEG. Delighted to see a neighbor across the Delaware River. Happy you are here.

Finally, Conrad Schneider, Advocacy Director for the Clean Air Task Force. We are happy to see you today. Thank you for coming.

Again, we would ask you to limit your statements to about 5 minutes each. The full content of your written statements will be included in the record.

With that, Mr. Snyder, you are recognized. Please proceed.

STATEMENT OF JARED SNYDER, ASSISTANT COMMISSIONER FOR AIR RESOURCES, CLIMATE CHANGE AND ENERGY, NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Mr. SNYDER. Thank you, Senator Carper.

Good morning, Senator Carper and members of the Subcommittee. I am Jared Snyder. I am the Assistant Commissioner for Air, Climate Change and Energy at the New York State Department of Environmental Conservation.

I have been involved in efforts to reduce transported air pollution for approximately 15 years, first as an attorney for New York, then in my current capacity as a policymaker. Based on that experience I can say that as a result of your leadership, Senator Carper, and the hard work of EPA over the last couple of years, the forecast for clean air is much brighter now than it has been for a long time and certainly brighter than it was 2 years ago when I last testified before this panel.

So I thank you for your leadership, Senator Carper, and for the opportunity to testify today on this important transport proposal of EPA's.

Now, even a cursory review of this proposal reveals that it is an improvement over the CAIR Rule. The Transport proposal requires substantial reductions of sulfur dioxides. Those will help in reducing fine particulate pollution through the eastern half of the country. These reductions will have dramatic public health benefits, saving the lives of thousands of Americans annually.

The proposal will also set specific emission caps for each State, requiring that each covered States reduces its SO_2 emissions substantially. Because it does not allow sources to use banked emission allowances the required emission reductions will occur sooner under this proposal than they would have occurred under CAIR.

This is just part of the good news. It actually gets better. Next month EPA will finalize a new ozone standard which will set the Nation on a path to having the cleanest air in decades.

But the bad news is that there is a disconnect between those two actions. Although EPA recognizes that much lower ozone levels are needed to protect public health, it has designed the Transport Rule only to meet the obsolete and unprotective 1997 standard.

I understand why EPA did that, but that is not providing the protection that we need. Simply put, the proposal will do very little to address the elevated levels of ozone that still plague the eastern half of the country.

To its credit EPA does commit to a second transport rule, but more is needed now. This summer so far has provided irrefutable evidence in the forms of dozens of exceedances of EPA's ozone standards across the eastern half of the United States. Over the July 4th weekend in New York alone, we saw 27 exceedances of that 2008 standard. And that standard is more lenient than the one that EPA is announcing next month. So more NO_x reductions are needed.

Now, we know from experience that control of NO_x emissions from the power sector is one of the most cost effective ways of reducing ozone levels. And we know now that the technology and labor resources are available to achieve those reductions now. For New York and other States burdened by elevated ozone levels this is a very important issue. Once EPA finalizes the new standard next month, we will have our work cut out for us in meeting this standard by the statutory deadlines.

In the Northeast we have harvested the low hanging fruit years ago. Like Maryland, New York has reduced NO_x emissions 80 percent from the power sector over the last decade and a half. And although we have already implemented dozens of strategies to reduce ozone levels in the Northeast, we are going to have to dig even deeper to meet the new standard, requiring the implementation of ever more costly standards.

But under no circumstances will we be able to meet a new, tighter standard without substantial regional reductions from the power sector as well as the implementation of other regional and national programs.

We have urged EPA to address this important issue now in its Transport proposal. We had hoped that EPA would base this proposal on the 2008 NAAQS. Now, EPA has another option available, which is basing the final rule's emission reductions when this rule goes final on the ozone standard that it will adopt next month.

EPA's alternate path forward, a second transport rule, will eventually result in the reductions needed if all goes as planned. But as I explain in more detail in my written testimony that will involve a substantial delay during which the adverse health effects will continue.

We believe that those reductions can be achieved within the next 2 years. The technology is available. And those reductions will also have benefits; greater NO_x reductions will have benefits that greatly exceed the cost. So we look forward to working with EPA to accelerate the reductions needed to enable us to meet the ozone standard.

Thank you again for the opportunity to testify.

[The prepared statement of Mr. Snyder follows:]

Testimony of

Jared Snyder
Assistant Commissioner for Air Resources, Climate Change and Energy
New York State Department of Environmental Conservation
625 Broadway, 14th Floor
Albany, New York 12233-1010

Before the

U.S. Senate Committee on Environment and Public Works
Subcommittee on Clean Air and Nuclear Safety
"Oversight: EPA's Proposal for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone."
406 Dirksen Senate Office Building
Thursday, July 22, 2010, 10:00 AM

My name is Jared Snyder and I am the Assistant Commissioner of the New York State Department of Environmental Conservation for Air Resources, Climate Change and Energy. I am New York's representative on, and a past Chair of, the Ozone Transport Commission (OTC), a body established by the 1990 amendments to the Clean Air Act to coordinate activities of the twelve states and the District of Columbia that comprise the ozone transport region (OTR). Although I am familiar with the views of the OTC on the interstate transport of air pollutants, I am testifying today only on behalf of New York.

Introduction

I appreciate the opportunity to testify today about EPA's July 6, 2010 proposed air pollution transport rule (the "transport proposal"). At this time, I can offer only a preliminary reaction to this proposal, which is over one thousand pages in length. As I will explain, however, even a preliminary review reveals that this proposal makes many improvements on the 2005 Clean Air Interstate Rule (CAIR) that it will replace. The transport proposal requires substantial reductions of sulfur dioxides (SO2) and will help in reducing levels of fine particulate pollution throughout the eastern half of the country. It will set specific emission caps for each state, requiring each covered state to reduce its SO2 emissions substantially. Because it does not allow sources to use banked emission allowances, the required emission reductions will occur sooner than under CAIR. Although we undoubtedly will have comments to offer on the details, we generally support these and other aspects of EPA's proposal, as explained further below.

At the same time, however, the transport proposal's treatment of ozone is disappointing. Although we have made major strides in reducing the emissions of nitrogen oxides (NOx) and volatile organic compounds (VOCs) that contribute to elevated ozone levels, the ozone levels in the eastern United States are still unhealthy. To underscore this point, over the July 4th holiday weekend this year, New York State experienced 27 separate exceedances of the 2008 national ambient air quality standard (NAAQS) for ozone, a standard that EPA has determined is itself inadequate.

Next month, EPA will finalize its proposed rule to set a new NAAQS for ozone at a level between .060 and .070 parts per million, based on its determination that higher levels of ozone are not protective of public health. But the transport proposal is only targeted to reduce ozone levels to the much higher .084 level of the NAAQS set by EPA in 1997. Simply put, the transport proposal does not require the reductions in NOx emissions needed to lower the levels of ozone in the air that people breathe to healthful levels. Today I will focus on the inadequacy of the NOx reductions. But first, I will highlight the positive elements of EPA's proposal.

Benefits of the Transport Proposal

The SO2 reductions that will result from the transport proposal will result in substantial reductions in fine particulate levels. Although the SO2 cap is comparable to the cap imposed in the second phase of CAIR, the proposal's cap must be met earlier and must be achieved by actual emission reductions rather than the use of banked SO2 allowances. As a result, the public will reap the public health and environmental benefits of the SO2 cap sooner than under CAIR. The benefits of this proposal will include thousands of lives saved annually and other public health benefits that EPA values in the billions of dollars annually. The SO2 reductions will also reduce acid rain to the benefit of our lands, lakes and streams that are still being severely impacted by acid rain, and they will enhance visibility in our national parks and wilderness areas will be enhanced.

Two aspects of the transport proposal will help to ensure that all states that contribute materially to air quality problems in another state will participate in the solution. First, we commend EPA for applying a one percent contribution threshold in identifying the states that contribute to the inability of states located downwind to achieve or maintain compliance with the applicable NAAQS. This one percent contribution threshold is consistent with a joint recommendation made by the member states of the OTC and those that participate in the Lake Michigan Air Directors Consortium (LADCO). Second, EPA's use of state-specific caps also helps to ensure that each state contributes to improving impaired air quality in downwind states. Although EPA's use of "variability limits" allows emissions in each state to exceed the cap by a small margin in some years, overall regional emissions must remain below the regional cap. Although we will have some comments to offer on the implementation of the state-specific caps, EPA's approach is an improvement over CAIR.

Finally, we fully support EPA's decision to create new allowances for each of the pollutants covered by the proposal. By not allowing the use of old allowances, EPA eliminated the large banks of allowances that could have been used to delay timely reduction of pollution that contributes to nonattainment or interferes with maintenance of the applicable NAAQS.

Inadequacy of the NOx Reductions

While EPA is to be applauded for many aspects of the proposal, the NOx reductions are inadequate to achieve healthful ozone levels. For people with asthma and other respiratory illnesses, this means visits to the emergency room and the horrible feeling of not being able to breathe. For the millions of healthy Americans living in the eastern United States, this means more spring and summer days with warnings against outdoor exercise and other physical activity. This proposal, if finalized, will not address what we know right now – that more NOx reductions are needed to remedy the elevated ozone levels experienced across the eastern United States every summer. In fact, as EPA concedes, the proposal may not even lead to regionwide attainment of the inadequate and obsolete 1997 standard for ozone.

From the perspective of reducing ozone, the transport proposal may not even be an improvement on CAIR and it may not result in any NOx reductions beyond those that have already been achieved. Direct comparison with CAIR is complicated by the fact that the states covered by the transport proposal are not identical to those covered by CAIR. But a comparison can be made of the caps applicable to the states that are encompassed within both CAIR and the transport proposal. Under CAIR phase 2, which was to begin in 2015, the ozone season budget for the states that are also covered by the transport proposal was 429,000 tons. The ozone season budget for the same states under EPA's current proposal is 475,000 tons. Although that cap level is less than the CAIR phase 1 budget of 507,000 tons, it is well above current emissions in those states, which totaled only 407,000 tons in 2009. For the people of New York, who have suffered through elevated ozone levels this summer, this aspect of the transport proposal is particularly troubling, especially considering that EPA's modeling in this proposal indicates that the New York City metropolitan area will continue to be challenged to maintain compliance with the 1997 ozone standard.

We recognize that the die was cast to a large degree by decisions made under the prior administration. As the Court of Appeals found, EPA did not adhere to the requirements of the Clean Air Act in adopting CAIR. EPA compounded that error by replacing the ozone standard underlying CAIR with a new standard that did not provide the public health protection deemed necessary by EPA's own expert scientific advisors. As a result, the Obama Administration inherited a significant challenge. EPA was required by a court order to issue a rule that addressed the shortcomings of CAIR and was based on the applicable air quality standards. But EPA was in the process of reconsidering the ozone standard that would govern that determination. That led EPA to face the question of which ozone standard should be the focus of the transport rule: the obsolete and unprotective 1997 standard, the better but still inadequate 2008 standard, or the upcoming standard to be announced in August.

In this rule, EPA has decided to base the emission reductions on those needed to meet the least protective alternative – the 1997 ozone standard. This is truly an ironic outcome. Because EPA has determined that the 2008 standard is not protective, it is basing the transport rule on the even less protective 1997 standard. New York and many other states in the east are already meeting, or close to meeting, the obsolete 1997 standard and, as a result, significant additional regional emission reductions may not be needed to meet that standard (unless the high ozone levels seen so far this summer continue). But substantial reductions in NOx emissions undoubtedly would be needed to meet either the 2008 standard or a new, even lower, standard that EPA is expected to propose next month.

New York and the OTC states urged EPA to base the transport proposal on the 2008 ozone standard that EPA is now reconsidering. Although we agree with EPA that

that standard is inadequate, it does provide more protection than the 1997 standard. But another option is now available. EPA will be finalizing a new ozone standard next month, well before it finalizes the transport proposal next spring. To provide the public with the reduced ozone levels that public health protection requires, we urge EPA to base its final transport rule next spring on the requirements that will exist at that time, including the new ozone standard to be announced next month.

To its credit, EPA has created a template for achieving reductions needed to comply with the revised ozone standard that it intends to issue next month. Under the expedited implementation schedule that EPA has described for a new ozone standard, EPA plans to designate nonattainment areas (areas not projected to attain the NAAQS) by August 2011; state implementation plans to achieve compliance with the NAAQS in those nonattainment areas would be due in December 2013; and nonattainment areas designated as "moderate" nonattainment would need to achieve compliance with the standard by 2017. In the transport proposal, EPA has explained that it plans to issue a second transport rule in 2012 to require the regional reductions in NOx emissions needed to achieve compliance with the new ozone standard.

Unfortunately, even if everything goes according to schedule, EPA's strategy may not produce emission reductions in time to meet the 2017 attainment deadline. In order for states to demonstrate compliance with a new standard by 2017, emission reductions should be achieved by the beginning of the ozone season in May 2014, since attainment is based upon the latest three years of air quality data. In the current transport proposal, EPA expresses its view that polluting sources cannot be expected to have controls installed and operational until the beginning of 2014. If EPA applies the same constraints to the second transport rule, to be finalized in 2012, it is not likely that EPA would set a schedule that requires additional reductions prior to 2015, at the earliest, too late for states in the east to demonstrate compliance by 2017.

A second concern we have with the ozone portion of the proposal is that EPA recognizes that its proposal may not fully address all sources of NOx reductions needed to enable compliance with the 1997 ozone standard. EPA states it "must determine whether further NOx reductions are warranted in certain upwind states that affect two or three areas with relatively persistent ozone air quality problems." (Transport proposal, pg. 17.) These areas are Houston and Baton Rouge, which may have difficulty achieving the standard, and the New York City metropolitan area, which could have difficulty maintaining its compliance with the standard. Although EPA states that it will address these issues in future rulemakings, further delay in any reductions that may be needed to address the 1997 ozone standard is unfortunate.

More NOx reductions can and should be achieved now. Based upon EPA's evaluation of costs and benefits associated with the proposal, approximately $40 of benefit is realized for each dollar of cost incurred by industry and society. This is consistent with the analyses conducted by New York and the OTC states, which demonstrate that reductions from the power sector are highly cost-effective compared to other ozone reduction strategies. Nevertheless, in order to reduce ozone levels, New

York and the other OTC states have implemented numerous strategies to reduce ozone levels, from imposing more stringent requirements on power plants and factories to adopting California's stringent automobile emission standards and regulating paints, gas cans and other consumer products. When EPA strengthens the ozone standard, we will find it more difficult, if not impossible, to achieve compliance with that standard without the benefit of substantial, cost-effective, regional emission reductions from the power sector.

The issue goes beyond simply meeting an obligation that the Clean Air Act places on states to demonstrate compliance with the applicable NAAQS. Elevated levels of ozone lead to asthma attacks and other respiratory illness, and contribute to increased mortality. Simply put, regional NOx reductions beyond those required by the transport proposal will make it easier for residents of the eastern United States to breathe on hot summer days. The NOx reductions will have many additional environmental benefits beyond reduced ozone levels. The reduction in NOx emissions will further reduce the acid deposition that decimates the lakes and streams in New York's Adirondack park region and other portions of the northeast. Further NOx reductions would also improve visibility in our national parks and other natural areas. NOx reductions are also essential to reducing the excessive nitrogen deposition in sensitive coastal ecosystems such as Chesapeake Bay and Long Island Sound.

Conclusion

Regardless of whether EPA sets the new ozone standard at .070 parts per million or at a lower level, meeting the standard will pose a tremendous challenge for states across the east and in many other parts of the country. In New York this summer, we have experienced many days with ozone levels well above that standard. To have any chance of reducing those ozone levels and complying with a new ozone NAAQS, we will need regional NOx reductions that are much more substantial than EPA is proposing now. Requiring those reductions in this transport proposal will result sooner in cleaner air and fewer asthma attacks and other illnesses for people across the eastern United States.

Attachment

Question from Senator Alexander:

In your testimony you conclude that CATR will yield a higher reduction in SO_2 emissions earlier than CAIR would have. Part of this reason is utilities would not be permitted to use banked SO_2 allowances. Do you have concerns that Utilities will use banked SO_2 allowances more generously prior to implementation of the rule because after the CATR rule is implemented those allowances are obsolete? Would this behavior result in higher emissions?

Response: The proposal not to allow Title IV allowances to be used in the transport rule SO_2 Trading Program will result in greater emissions reductions than CAIR. However, the Transport Rule may provide electricity generating units covered by both Title IV and the Transport Rule with an incentive to use excess Title IV allowances in the time prior to the start of the Transport Rule, unless EPA implements mechanisms to prevent or mitigate this outcome when it finalizes the Transport Rule. We are unaware of any analysis that has been undertaken of the extent to which emissions of SO2 will increase prior to the implementation of the Transport Rule. In any event, we anticipate that any increase in emissions would be temporary and would cease by 2012, when the Transport Rule would be implemented.

Senator CARPER. Thank you, Mr. Snyder. Good to see you, thanks for your testimony and for working with us.

Chris Korleski, please proceed. Welcome. Your entire statement will be made a part of the record.

STATEMENT OF CHRIS KORLESKI, OHIO ENVIRONMENTAL PROTECTION AGENCY

Mr. KORLESKI. Good morning. I am Chris Korleski, Director of the Ohio EPA. I would like to thank the Chairman, Ranking Member, and all the members of the Subcommittee for the opportunity to discuss the proposed Interstate Transport Rule.

First, I do—just in light of Senator Voinovich's comments, Mr. Chairman, I do want to commend USEPA in general and Gina McCarthy. I do have the greatest respect for Gina McCarthy. She works very hard; we are good friends, and I commend them for the work that they have done here.

Senator CARPER. We will note that in the record. I saw members of her staff writing that down.

[Laughter.]

Mr. KORLESKI. As you know, the Clean Air Act requires States to develop approvable State Implementation Plans, SIPs, which set for the emission reduction measures that States will implement to achieve attainment within the NAAQS and address the transport of air pollutants downwind from upwind States. This now soon to be moribund CAIR served as an integral component of Ohio's plans to achieve necessary reductions in NO_x and SO_x from power plants.

Without question the NO_x and SO_x emissions under CAIR would have greatly assisted Ohio and other States in attaining the standards for both PM and ozone and in addition were an essential component of USEPA's plan for addressing regional haze.

Before I go into detail about the Interstate Transport Rule, it is very important that the panel be aware of the significant progress that Ohio has made in achieving ambient air quality standards. In the late 1970s the highest 8-hour ozone values we were measuring were over 140 parts per billion. Now, the worst sites in the States are in the range of 80 parts per billion. Currently the entire State is designated attainment for the 1997 ozone standard of 84 parts per billion, something that was unthinkable even 5 or 6 years ago.

This progress has come primarily as a result of the hundreds of millions of dollars invested in air pollution control equipment in the State. However, we also recognize that more dollars and more effort will be needed to meet the seemingly ever increasingly restrictive air quality standards for ozone and other pollutants as well. We strongly support the concept of regulating the interstate transport of air pollution, and therefore we supported USEPA's promulgation of CAIR.

We also understand USEPA's mandate to address judicially recognized flaws in CAIR. As we know, recently USEPA announced the proposal of the new interstate Transport Rule as a replacement for CAIR. Now, as has been pointed out I think by everyone, due to the length and complexity of the proposal, and it is very long, my comments must reflect a first impression of the proposed rule. But we do have some concerns that we would like to address today.

First, we note that USEPA plans to implement a Federal implementation plan, or a FIP, for the Interstate Transport Rule. Although we understand the need for emission reductions as soon as possible, this concept of FIP first appears to usurp the fundamental right of the States to develop their own SIPs. The USEPA proposal goes into detail on how States are free to develop State plans as alternatives to the FIP, but it also makes clear that USEPA is unsure about and taking comment on the appropriate criteria for approval of these plans.

In other words we are free to start work on our SIPs, but we cannot be certain as to their approvability until USEPA finalizes those criteria, which is going to take time. In our view this FIP first approach is not consistent with the spirit of cooperative federalism which has historically reflected how the Clean Air Act has worked.

Second, we do not understand the significant differences in USEPA's approach to the proposed budget for SO_2 as compared to the proposed budget for NO_x. Under CAIR the State budget for SO_2 for electric generating units in 2010 was roughly 333,000 TPY. And in 2015 was roughly 233,000 TPY, that is tons per year.

Under the Interstate Transport Rule USEPA is proposing a much more restricted limit of 178,000 TPY in 2014. In 2009 Ohio utilities emitted over 600,000 tons per year of SO_2. Achieving these substantial SO_2 reductions to meet this proposed SO_2 limit will be a difficult task in the timeframe proposed. Additional time may be needed. Further, additional tightening of the SO_2 budget in the future may simply not be technically feasible.

Conversely, with respect to NO_x we believe that the proposed limits can actually be tightened. The CAIR NO_x budget for Ohio was roughly 45,000 tons during the ozone season of 2009, dropping to 39,000 tons in 2015. The Interstate Transport Rule proposes a budget of 40,000 tons in 2012. In contrast Ohio utilities emitted roughly 36,000 tons in 2009, due in part to a cool summer.

In short the 2009 NO_x emissions from Ohio utilities were less than the proposed 2012 NO_x emissions budget. It would be our preference to see a more restrictive NO_x budget, adequate time to reach that lower NO_x level, and most importantly, have those NO_x levels maintained for an extended time period.

Next, we are concerned with the concept—and this is the concept that Senator Voinovich homed in on earlier—we are concerned with the concept that each time USEPA promulgates a new, more restrictive air quality standard USEPA intends to revise the Interstate Transport Rule by changing the emission budgets. To cut my testimony short I will just say we are concerned about continual changes, continual whiplash on our part and the regulated entities' part due to continual changes, and that is a concern to us.

Senator CARPER. I would ask you to go ahead and wrap it up if you would, please.

Mr. KORLESKI. We continue to believe that the best approach to reducing SO_2 and NO_x emissions would include a surgical legislative fix that will allow USEPA to mandate a reasonable level of control and would clearly grant USEPA the authority to set up a more comprehensive trading program.

I apologize for going over, and I thank you.

[The prepared statement of Mr. Korleski follows:]

Ohio | Environmental Protection Agency

Ted Strickland, Governor
Lee Fisher, Lt. Governor
Chris Korleski, Director

Testimony of Chris Korleski
Director of the Ohio Environmental Protection Agency

Before the
U.S. Senate Subcommittee on Clean Air and Nuclear Energy;
Senate Environment and Public Works Committee

July 22, 2010

Good morning. I'm Chris Korleski, Director of the Ohio Environmental Protection Agency (Ohio EPA). I would like to thank the Chairman, Ranking Member, and all the members of the Subcommittee for the opportunity to discuss the U.S. EPA proposed Interstate Transport Rule.

As I begin my comments this morning, I would first like to thank and acknowledge the efforts of our federal colleagues at U.S. EPA for their work on this important, difficult, and long-in-coming rule package. Anyone familiar with the history of the Clean Air Interstate Rule (CAIR) is aware of the bumpy and circuitous route leading up to U.S. EPA's recent proposal, and while we may have some concerns and questions regarding the proposed rule, I certainly commend U.S. EPA for its diligent efforts.

As you know, the Clean Air Act requires states to develop approvable state implementation plans (SIPs) which set forth the emission reduction measures that states will implement in order to achieve attainment with the national ambient air quality standards (NAAQS) and address the transport of air pollutants downwind from upwind states. The now-moribund CAIR served as an integral component of Ohio's plans to achieve necessary reductions in both nitrogen oxides (NO_x) and sulfur dioxide (SO_2) from power plants. Without question, the NO_x and SO_2 emission reductions under CAIR would have greatly assisted Ohio and other states in attaining the standards for both particulate matter (PM) and ozone and, in addition, were an essential component of U.S. EPA's plan for addressing regional haze.

Before I go into detail about the Interstate Transport Rule, I think it is important that the panel be aware of the significant progress that Ohio has made in achieving ambient air quality standards. In the late 1970s, the highest eight-hour ozone values we were measuring were over 140 parts per billion; now the worst sites in the state are in the range of 80 parts per billion. Currently, the <u>entire state</u> is designated attainment for the 1997 ozone standard of 84 parts per billion. This progress has come primarily as a result of the hundreds of millions of dollars invested in air pollution control equipment in the state. However, we also recognize that more dollars and effort will be needed to meet the seemingly ever-increasing restrictive air quality standards for ozone and other pollutants as well.

Ohio strongly supports the concept of regulating the interstate transport of air pollution and therefore supported U.S. EPA's promulgation of CAIR. We also understand U.S. EPA's

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mandate to address judicially recognized flaws in CAIR. On July 6, 2010, U.S. EPA announced the proposal of the new Interstate Transport Rule as a replacement for CAIR. Due to the length and complexity of the proposal, my comments only reflect a first impression of the proposed rule. However, Ohio EPA does have some concerns that we would like to speak to today.

First, we note that U.S. EPA plans to implement a Federal Implementation Plan (FIP) for the Interstate Transport Rule. Although we understand the need for emission reductions as soon as possible, this appears to usurp the fundamental right of the states to develop their own SIPs. The U.S. EPA proposal goes into detail on how states are free to develop state plans as alternatives to the FIP, but also makes clear that U.S. EPA is unsure about (and taking comment on) the appropriate criteria for approval of these state plans. In other words, states are free to start work on their own plans, but cannot be certain as to their approvability until U.S. EPA finalizes those criteria, which will undoubtedly take some time. In our view, this "FIP first" approach is not consistent with the spirit of cooperative federalism imbedded in the essential structure of the Clean Air Act.

Second, we do not understand the significant differences in U.S. EPA's approach to the proposed budget for SO_2 as compared to the proposed budget for NO_x. Under CAIR, the state budget for SO_2 for electric generating units in 2010 was 333,520 tons per year and in 2015 was 233,464 tons per year. Under the Interstate Transport Rule, U.S. EPA is proposing a much more restricted limit of 178,307 tons per year in 2014. In 2009, Ohio utilities emitted 600,689 tons per year of SO_2. Achieving the substantial SO_2 reductions to meet this proposed SO_2 limit will be a difficult task in the timeframe proposed and additional time may be needed. Further, additional tightening of the SO_2 budget in the future may simply not be technically feasible.

Conversely, with respect to NO_x, we believe that the proposed limits can actually be tightened. The CAIR NO_x budget for Ohio was 45,664 tons during the ozone season of 2009, dropping to 39,945 tons in 2015. The Interstate Transport Rule proposes a budget of 40,661 tons in 2012. In contrast, Ohio utilities emitted 36,076 tons in 2009 (due in part to a relatively cool summer). In short, the 2009 NO_x emissions from Ohio utilities were less than the proposed 2012 NO_x emissions budget. It would be our preference to see a more restrictive NO_x budget, adequate time to reach that lower NO_x level, and then have those NO_x levels maintained for an extended time period.

Next, we are concerned with the concept that each time U.S. EPA promulgates a new (more restrictive) air quality standard, U.S. EPA intends to revise the Interstate Transport Rule by changing the emission budgets. We have two main concerns with this approach. First, we expect that at some point, it will be difficult or impossible to develop and implement technology that can achieve the new, more restrictive budgets. Second, the regulated community must have some degree of certainty to timely plan investments in controls, fuels, and operations at generating facilities in order to achieve necessary emission levels by the relevant deadline. We would recommend that any budget U.S. EPA promulgates for an emissions sector would not change for at least ten years and then only if U.S. EPA demonstrates that additional controls are technically achievable and cost effective.

Finally, we continue to believe that the best approach to reducing SO_2 and NO_x emissions from utilities would include a surgical legislative fix that, while allowing U.S. EPA to mandate a reasonable level of control, would clearly grant U.S. EPA the authority to set up a more comprehensive trading program to allow for more trading opportunities for criteria pollutants.

Thank you for your time. I would be happy to answer any questions.

Senator CARPER. We very much appreciate your being here today. Thanks for your work. Our best to Ohio.

Mr. Svenson, of the PSEG, please proceed.

STATEMENT OF ERIC SVENSON, VICE PRESIDENT, POLICY AND ENVIRONMENT, HEALTH AND SAFETY, PUBLIC SERVICE ENTERPRISE GROUP

Mr. SVENSON. Thank you very much, Mr. Chairman.

Mr. Chairman and members of the Subcommittee, I am pleased and honored to appear before you today on behalf of Public Service Enterprise Group.

PSEG is one of the Nation's largest independent power producers with more than 16,000 megawatts of electric generating capacity in the Northeast and in Texas. This includes 2,400 megawatts of coal-fired generation capacity and 3,700 megawatts of nuclear capacity. We offer the following reactions to the EPA's draft Transport Rule, which we believe is essential to meet the air quality goals of the Clean Air Act.

First, PSEG believes that the electric power industry can meet the emission caps and the timelines proposed by the Transport Rule. Second, we believe the Rule's preferred approach of a cap and trade with intrastate and limited interstate trading provides a reasonable compliance structure given the constraints imposed on EPA by the D.C. Circuit Court's opinion.

However, we believe the program would be better served by providing for a more robust trading market and better integrating the program with the existing title IV SO_2 allowances. We recognize that it might require legislation to address these issues.

Third, regulatory certainty is critical for the electric power industry to be able to make long-term capital investments. Given the repeated litigation delays surrounding the EPA's air regulations we believe comprehensive legislation limiting power plant emissions with a robust trading mechanism that ensures achievement of National Ambient Air Quality Standards would provide the certainty our industry needs to make the right investment decisions.

So let me elaborate briefly on each of these points. PSEG's electric generating fleet is among the cleanest in the country through significant investments in pollution control technologies such as scrubbers, SCRs and new clean generation. In the past 5 years we have invested more than $2 billion to improve the environmental performance of our generating fleet.

As a result, we are very familiar with the technologies, the capital costs, and the logistics needed to comply with the proposed transport rule. Now, while the transport rule is quite complex and we continue to evaluate its details, we are supportive of the proposed emission caps for NO_x and SO_2 as well as the proposed compliance timelines. This program is essential to help States attain the current ozone and fine particulate National Ambient Air Quality Standards while providing substantial human health and environmental benefits as projected by EPA.

In addition, it provides a reasonable compliance construct for updating emission caps to meet the new National Ambient Air Quality Standards. We believe that the electric power industry is capable of meeting its obligations under the Transport Rule while maintaining electric system reliability. The industry already has made substantial investments in air pollution technologies. The industry has excess generating capacity available to absorb the potential power plant retirements associated with this rule.

And electric market operators in the industry sector have broad ranges of strategies available to them for reducing emissions while maintaining electric system reliability, including energy efficiency, load management strategies and the addition of renewable energy capacity. PSEG alone is investing over $1.25 billion in energy efficiency and renewable energy capacity.

As I indicated earlier we do have some concerns that largely stem from the D.C. Circuit's opinion. PSEG is a strong supporter of market-based regulatory approaches because of their cost effectiveness. We would encourage EPA to establish a robust trading market.

We are concerned that some of the options proposed by EPA may significantly curtail the trading of allowances. Additionally, because the Rule's preferred allocation method does not utilize existing title IV allowances, companies such as PSEG that have invested in pollution control equipment are effectively penalized as the value of their banked allowances are significantly reduced.

Given the Court's decision both of these issues may be better addressed through legislation which could restore confidence in the market and ensure the ongoing value of allowances. Mr. Chairman, PSEG was an early proponent of your Clean Air Planning Act. We continue to urge Congress to enact this year a market-based program that limits the electric sector's greenhouse gas emissions. And we believe your proposed legislation, the Clean Air Act Amendments of 2010, would provide greater long-term business certainty than would otherwise be provided by the Transport Rule.

So Mr. Chairman and members of this Committee, I thank you for the opportunity and your consideration of my comments and would welcome any questions you may have.

[The prepared statement of Mr. Svenson follows:]

Written Testimony

Eric Svenson, Vice President
Policy and Environment, Health & Safety
Public Service Enterprise Group

To

United States Senate
Committee on Environment and Public Works
Clean Air and Nuclear Safety Subcommittee

Oversight: EPA's Proposal for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone

July 22, 2010

Good morning Chairman Carper, Senator Vitter, and Members of the Subcommittee. I am pleased and honored to appear before you today on behalf of Public Service Enterprise Group Incorporated (PSEG). My name is Eric Svenson, Vice President of Policy and Environment, Health & Safety at PSEG. Mr. Chairman, I would like to thank you for the opportunity to testify on behalf of PSEG on EPA's proposed Transport Rule. The rule is designed to limit emissions of SO_2 and NO_x from power plants in 31 states and the District of Columbia.

PSEG supports EPA's efforts to address the persistent ozone and fine particle nonattainment challenges in the Eastern U.S. by limiting air pollution transport under the "good neighbor" provisions of the Clean Air Act, and I want to start by offering the following key points in response to EPA's proposed rule:

1. First, PSEG believes that the electric power industry can meet the emissions caps and timelines proposed by the Transport Rule. The emissions reductions proposed are essential to meet the air quality goals required by the Clean Air Act and would achieve the substantial human health benefits identified by EPA.
2. Second, we believe the rule proposes a reasonable compliance structure given the constraints imposed on EPA by the D.C. Circuit Court's decision to remand the Clean Air Interstate Rule (CAIR). We believe it is important to facilitate a more robust trading market and better integrate the program with the existing Title IV SO_2 allowances, but we

recognize that it might only be possible to address these issues through new federal legislation.

3. Regulatory certainty is critical for the electric power industry to be able to make long-term capital investments. We have seen repeated legal delays and resulting uncertainty with EPA's air regulations. We continue to believe comprehensive legislation limiting power plant emissions with a robust trading mechanism that ensures compliance with the national ambient air quality standards (NAAQS) would provide the certainty our industry needs to make the right investment decisions.

PSEG

PSEG is a publicly traded diversified energy company with annual revenues of more than $12 billion. Our family of companies distributes electricity and gas to more than two million utility customers in New Jersey and owns and operates approximately 16,000 megawatts of electric generating capacity concentrated in the Northeast, Mid-Atlantic, and Texas. We own a diverse fleet of generating units, including 2,400 megawatts of coal-fired capacity and 3,700 megawatts of nuclear capacity.

PSEG has long supported an integrated, multi-pronged strategy to reduce power plant emissions, and we have worked closely with our state and federal partners to advance this goal. We have strongly supported Senator Carper's multi-pollutant legislation because it provides the electric power sector with a greater degree of business certainty as we make long-term investment decisions. We have advocated for tighter limits on power plant NO_x and SO_2 emissions in order to address the air quality challenges that have plagued the state of New Jersey and other states in the region. The New Jersey DEP estimates that 26 to 82 percent of the ozone problem under the current NAAQS in New Jersey stems from upwind sources of pollution outside of the state, and as EPA tightens the NAAQS, this contribution will only increase.

PSEG has also been a leader in proactive environmental action and has invested heavily in new, clean generation. Since 1990, PSEG has invested more than $3 billion to replace inefficient, older generating units and upgrade existing facilities in New Jersey, New York, Connecticut, Pennsylvania, and other states. Two-thirds of this spending has occurred in the last five years.

Through these efforts, PSEG has dramatically lowered its emissions of NO_x, SO_2, and fine particulate matter. Today, our domestic electric generation fleet is among the cleanest in the country, and our performance will continue to improve as we complete the installation of advanced emissions control technologies – including SCRs, SO_2 scrubbers and baghouses – at our New Jersey coal-fired units by the end of this year. We have invested to reduce mercury and other emissions at our Connecticut coal plant. Through the installation of a baghouse and carbon injection system, we have reduced the plant's mercury emissions by more than 90 percent. In Pennsylvania, we have retrofitted the Keystone facility with both an SCR and a SO_2 scrubber. Additionally, the Conemaugh facility in Pennsylvania has been retrofitted with an SO_2 scrubber, and we are evaluating whether to also add an SCR system for NOx control.

Our efforts are also creating jobs. For example, installing the latest emissions control equipment at both our Mercer and Hudson plants created approximately 1,600 construction jobs at the peak of construction. In addition, we are adding staff – approximately 25 new positions at each plant – to operate and maintain the equipment which, we estimate, will reduce mercury, NOx, SO_2 and particulate matter emissions by 80 to 90 percent or more.

We are also investing over $1.25 billion in energy efficiency and renewable energy capacity. As a result, we are very familiar with the technologies, capital costs, and logistics associated with meeting the requirements of a regulation such as EPA's proposed Transport Rule. Moreover, we will have completed these investments four years in advance of the schedule contemplated by the Transport Rule.

As EPA notes in the proposal, the Transport Rule is the first of several rules to be issued over the next two years that will target power plant emissions. It should come as no surprise to the industry that EPA is seeking to further limit NO_x and SO_2 emissions as well as other air pollution emissions. Most companies, including PSEG, have continued with the installation of controls despite the legal uncertainties created by the challenges to CAIR. We believe it is important for EPA to move forward with the Transport Rule and are encouraging EPA to coordinate its upcoming rules to the extent that it has the authority to do so.

Benefits of the Transport Rule

While the rule is quite complex, and we continue to evaluate the many details of the proposal, we are supportive of the proposed emission caps for NO_x and SO_2 as well as the timelines for the reductions. The rule also establishes an important framework by which EPA can revise the Transport Rule to provide further reductions to address any revised NAAQS. By 2014, EPA estimates that the Transport Rule, in combination with other state and EPA actions, will reduce power plant SO_2 emissions by 71 percent and NO_x emissions by 52 percent below 2005 levels. Although the court remanded all of CAIR, the electric power industry remains on track to achieve much of these reductions based on the installations that were planned to comply with CAIR.

EPA's air quality modeling demonstrates that the Transport Rule will help bring most areas in the Eastern U.S. into attainment with the 1997 ozone and fine PM NAAQS. Most significantly, EPA has concluded that the Transport Rule will ensure the achievement of important health benefits that should not be delayed. EPA's analyses explain that fine particulates, formed, in part, by NO_x and SO_2, contribute significantly to respiratory problems such as asthma attacks and chronic bronchitis, significant health problems such as heart attacks, and premature deaths. Additionally, NO_x contributes to the formation of ground-level ozone, which has been linked to respiratory problems and can also lead to premature death. EPA estimates the annual benefits of the proposed rule range from \$120-\$290 billion (2006 \$) in 2014. EPA predicts that by implementing the proposed rule, 14,000 to 36,000 premature deaths will be avoided as well as 23,000 non-fatal heart attacks.

In addition to the health benefits of the rule, by bringing these areas into attainment, EPA is lifting an important economic barrier in regions where industrial facilities and power plants would otherwise be required to obtain emission offsets in order to expand their operations. This requirement discourages development due to the increased permitting and financial obligations compared to attainment areas.

Electric Power Industry Can Meet the Requirements of the Transport Rule

We believe that the electric power industry is capable of meeting its obligations under the Transport Rule and other provisions of the Clean Air Act while maintaining electric system reliability. While there may be isolated reliability issues that will need to be addressed, the Transport Rule and other air pollution regulations affecting the electric power industry can be effectively managed while maintaining electric system reliability. There are several factors that lead us to this conclusion.

- First, the industry has already made substantial investments in air pollution control technologies, as reflected in the substantial improvements that have occurred to date. Since 1990, power plant emissions of SO_2 and NO_x have been reduced by 64 percent and 70 percent, respectively, and over 65 percent of coal-fired generating capacity has been retrofitted with SO_2 scrubber controls or will soon have scrubber controls installed.

- Second, to the extent that the industry opts to retire some of its oldest generating units rather than investing in controls, this will likely have the largest effect on smaller, less efficient units, and we believe the electric system has the excess generating capacity necessary to absorb these retirements without impacting reliability.

- Third, the electric power sector has a broader range of strategies available for reducing emissions while maintaining electric system reliability beyond simply installing end-of-the pipe controls. Companies are making significant investments in new clean generation, energy efficiency programs, and load management programs. As I noted earlier, PSEG is planning to invest over one billion dollars in energy efficiency and renewable energy capacity. PJM recently completed a capacity auction to secure capacity resources to meet the region's electricity needs for 2013 and 2014. Three fourths of the new capacity resources clearing the auction came from renewable energy, demand response, and energy efficiency resources.

Potential Implications of Transport Rule for Allowance Markets

The D.C. Circuit court's CAIR decision limited EPA's authority to allow interstate trading. Despite this constraint, our first impression is that EPA has proposed a reasonable approach that balances the industry's ability to trade allowances and implement the most cost-effective control options while at the same time recognizing that the Clean Air Act requires EPA to prohibit emissions that significantly contribute to nonattainment or interfere with maintenance in downwind states. PSEG is a strong supporter of market-based regulatory approaches because of their cost effectiveness, and we hope that EPA will, at a minimum, preserve its preferred trading approach as it develops its final rule. The cap-and-trade approach has a long history of success in regulating power plant emissions.

Based on the D.C. Circuit's decision, the Agency is not proposing an allocation methodology that would rely on existing Title IV allowances to comply with the Transport Rule. This creates an unfortunate dynamic whereby companies, such as PSEG, that have invested in pollution control equipment are essentially penalized as the value of their banked allowances is reduced by exclusion of Title IV allowances in the new trading program. Additionally, the allocation structure proposed in the Transport Rule fails to recognize these early investments. These early reductions are the ones that EPA and Congress should be encouraging, and we are concerned that an unintended consequence of the proposal will be to deter companies from taking proactive actions to reduce emissions. PSEG believes it is important to restore this lost value, preferably by incorporating Title IV allowances into any new program, but at a minimum, allocating any new allowances in a manner that recognizes early investments to reduce emissions. The approach proposed by EPA rewards the highest emitting sources by allocating allowances based on emissions.

Both of these issues may be better addressed through legislation. Installing end-of-pipe pollution controls is a capital intensive undertaking requiring long-term investment decisions. A well-functioning market-based program encourages companies to make early reductions by giving them the confidence that allowances will have ongoing value. We are continuing to evaluate how the Transport Rule's trading may work in practice, but our initial impression is that its complex structure may significantly curtail the trading of allowances, driving up the costs of the program. Given that EPA's authority to establish a robust trading market is severely constrained, legislation could provide the market structure and certainty to allow the industry to make the investment decisions that achieve the greatest improvements in air quality.

Mr. Chairman, as I indicated earlier, PSEG was an early proponent of your Clean Air Planning Act, which would have established a national, multi-pollutant cap-and-trade program for the four major power plant pollutants -- SO_2, NO_x, mercury, and carbon dioxide. We are urging Congress to enact this year a market based program that reduces the electric sector's greenhouse gases emissions. Additionally, we believe your Clean Air Act Amendments of 2010, which would control emissions of NO_x, SO_2 and hazardous air pollutants, including mercury, would provide the necessary long-term business certainty and restore the allowance market that we believe the Transport Rule may not achieve.

Conclusion

In conclusion, we support EPA's efforts to help bring us closer to attainment of the important health standards and believe the Transport Rule provides a reasonable framework given the confines of the D.C. Circuit decision. We have concerns, however, with the limitations placed on allowance trading and the effect the program will have on Title IV SO_2 allowances. We believe there may be an opportunity to enact legislation that ensures a robust and equitable trading market with stringent emission caps to ensure attainment of the current and future NAAQS. We look forward to working with the Committee and your staff to evaluate whether Congress can pass such legislation this year.

Mr. Chairman and members of this Committee, thank you for your consideration, and I would welcome any questions you may have.

September 10, 2010

Ms. Heather Majors
Senate Committee on Environment and Public Works
410 Dirksen Senate Office Building
Washington, DC 20510

Re: Environment and Public Works Committee Hearing: July 22, 2010
Follow-Up Questions for Written Submission

Dear Ms. Majors:

Thank you for the opportunity to respond to the questions Senator Alexander submitted based on my testimony before the Comment on Environment and Public Works on July 22, 2010. The following are my responses to his questions:

1) *Since the CATR does not recognize banked allowances, do you think this leaves EPA open to litigation for taking assets?*

I do not believe the proposed Clean Air Transport Rule ("Transport Rule") leaves EPA open to significant litigation risk for the taking of assets. Section 403(f) under the Title IV "Acid Rain" provisions of the 1990 Clean Air Act Amendments state that any allocation does not create a property right. Specifically, the Clean Air Act states that:

> An allowance allocated under this subchapter is a limited authorization to emit sulfur dioxide in accordance with the provisions of this subchapter. Such allowance does not constitute a property right. Nothing in this subchapter or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. CAA § 7651b(f).

Thus, while there are many companies in the electric sector that have seen financial losses in their Title IV allowances, including PSEG, the allowances provided by Title IV never conferred a property right. These Title IV allowance financial losses are due to EPA implementing section 110 of the Clean Air Act to address SO_2 emissions as they relate to fine particulate pollution, as required by the D.C. Circuit's opinion on the Clean Air Interstate Regulation (CAIR). This creates an unfortunate dynamic whereby companies, such as PSEG, that have already invested in pollution control equipment to reduce SO_2 emissions are essentially penalized as the value of their Title IV banked allowances are significantly reduced. However, the only way to address this issue is to enact new legislation specifically authorizing EPA's use of the Title IV program for CATR, which I encouraged the committee to consider in my testimony.

2) *Given the limited trading that can occur under the proposed CATR, do you think it will be more expensive for a utility to comply with these reductions as compared to a full market based system similar to CAIR or the Clean Air Act Amendments of 2010 offered by Senator Carper and 15 others?*

We are still in the process of preparing PSEG's formal written comments to EPA on the proposed Transport Rule. However, given the constraints that the D.C. Circuit court imposed on EPA, I generally believe that the limited interstate trading option is about as robust as EPA could design and the program proposed is workable. If EPA had the authority to use the existing Title IV Acid Rain trading system to address fine particulate pollution, I am convinced such a full market based system would be less administratively burdensome and less costly for industry. But, simply authorizing a more full market based trading system in its own right without consideration to whether sufficient emission reductions will be achieved relative to their otherwise significant contributions to NAAQS non-attainment or interference with maintenance of NAAQS is problematic for many downwind states. Legislation, including the Clean Air Act Amendments of 2010 that Senators Carper and Alexander cosponsored, could provide the legislative authority for EPA to implement a more cost effective market-based program, but it is also important that any such legislative proposal ensure that emission caps are sufficiently stringent to ensure attainment and maintenance of the current and future NAAQS.

Again, thank you for the opportunity to testify before the Committee, and I would be happy to answer any additional questions any Members may have.

Sincerely,

Eric B. Svenson, Jr.
Vice President – Policy and
Environment, Health and Safety

Senator CARPER. Mr. Svenson, thank you for those comments. Special thanks to PSEG for working with all of us on these important issues for years. Thank you so much.

Conrad Schneider, welcome. Please proceed.

STATEMENT OF CONRAD G. SCHNEIDER, ADVOCACY DIRECTOR, CLEAN AIR TASK FORCE

Mr. SCHNEIDER. Thank you, Mr. Chairman, Senator Voinovich. My name is Conrad Schneider, Clean Air Task Force Advocacy Director. I appreciate the opportunity to speak to you today.

We are based in Boston, and we have been working on cleaning up power plant pollution since our founding in 1996. I know you all have been working on that since you were Governors, as well.

And I want to just acknowledge Senator Voinovich, whom I have been working with on this issue for so many years. I know he is retiring, and I wish him well; we all do. And I thank him and you, Mr. Chairman, for your persistence on this issue.

The first thing I want to do today is bring you some good news. And that is regarding the substantial progress that has been made on SO_2 emission reductions in the last 5 years. In 2004 SO_2 emissions nationally were 11 million tons a year. Last year, they had fallen to 5.6 million tons. That is a 50 percent cut in 5 years.

The cause? The cause was New Source Review enforcement actions by EPA and the States, effective new State regulations and compliance with the now-defunct CAIR rule. The economic recession did not cause these reductions. The installation of 130 scrubbers did.

Health researchers estimate that reductions of this magnitude can save tens of thousands of lives a year and note that these reductions came without any noticeable increase in electric prices, electricity bills, switching to natural gas, and without raising any reliability concerns whatsoever. Let me just repeat that: these reductions came without any noticeable increase in electricity prices, bills, switching to natural gas, and without raising any reliability concerns whatsoever.

However, continued progress is now in jeopardy because the D.C. Circuit struck down the CAIR Rule. Scrubbers have an operation and maintenance cost, so utilities will not run them unless they are required to do so. So without the Transport Rule, emissions will go up.

But even at today's pollution levels tens of thousands of American lives will be cut short, and there are still over 700 coal units that do not have scrubbers. It is high time for every coal plant in the U.S. to be well controlled. That is why it is so important for EPA to strengthen and finalize the Transport Rule. First, it will lock in the gains that we have seen over the last 5 years. But second, it goes further in 15 States and brings many if not all States into attainment.

Senators Carper and Voinovich, as Governors, you used to see maps in which your States were full of red, full of red non-attainment counties like the one that is shown on the screen here. But under the Transport Rule proposal almost all the red is gone. With some tightening of the Transport Rule it looks like EPA can get the red out completely. Senator Carper, I would urge you to insist that

EPA provide you a comparable map for your bill to see what it would do with respect to attainment in these same areas.

At a minimum EPA should complete the analysis it has begun relating to persistent non-attainment areas like Cleveland, Chicago, Houston, Baton Rouge, and New York City, requiring upwind controls to potentially solve these areas' problems and save many more lives. As the proposed rule would only require 14 gigawatts of additional scrubbers, and the benefits outweigh the costs 50 to 1, there is much more than can be done.

In addition we agree that EPA should tighten the NO_x cap in the east. These additional controls will be required to put those areas within striking distance of attainment.

We do not support the so-called fix proposed by Mr. Korleski. Note that the old war between the States, that is between the Northeast and the Midwest, is largely over. All States have realized that their pollution contributes to their neighbors' non-attainment. And Ohio is one of the biggest beneficiaries, if you see this particular map, in which 1,300 lives are saved per year, the most next to Pennsylvania.

In addition to supporting EPA's strengthening and finalizing the Transport Rule, we support passage of S. 2995, the Clean Air Act Amendments of 2010, sponsored by Senator Carper, you and Senator Alexander. We have long favored a comprehensive legislative solution of the problem of power plant pollution. We recognize that in producing the Transport Rule, EPA has done a good job of navigating the mine field laid for it by the D.C. Circuit. But we know that just as the CAIR Rule was challenged and struck down, so a new set of power plant regulations may be as well.

To guarantee the certainty of environmental improvement and public health benefit and the regulatory certainty that the electric power industry craves, Congress should act now to pass the bill. It would codify stringent national caps for SO_2 and NO_x while providing a crucial backstop for EPA's power plant air toxics rule. And your bill enjoys broad bipartisan support.

A comparison of the two bills to each other shows that your bill would save 44,000 more lives by 2025. And importantly EPA's analysis demonstrates that passage of the bill would result in no noticeable increase in electricity prices, natural gas prices and no appreciable decrease in coal generation or use.

Now, let me make just one final point. There has been a lot of discussion over the past couple of weeks about a possible climate title to a Senate energy bill. The focus is now on a power sector only bill. Especially where we are in this session, the Clean Air Task Force supports this approach. However, apparently some electric utilities are asking the Clean Air Act requirements for non-greenhouse gas pollutants, like today's Transport Rule and next year's MACT Rule, be scrapped in exchange for their support for the bill.

To this we believe you should say, no deal. Congress, in considering the Climate Bill, should lay down a firewall to ensure that no Clean Air Act rollbacks with respect to power plant, sulfur, nitrogen, or toxic emissions occur. We must continue to make progress and clean up our air as we address climate change. We should not trade off the right of our children today to breathe clean air for the right of our grandchildren to live in a world without global warming.

Senator Alexander said it best when he said last week: “You mean to spew more sulfur, nitrogen, and mercury and less carbon? That’s not my idea of progress.” And we agree with that statement.

Thank you very much, and I would be happy to answer any questions.

[The prepared statement of Mr. Schneider follows:]

BEFORE THE
CLEAN AIR SUBCOMMITTEE OF
THE ENVIRONMENT AND PUBLIC WORKS COMMITTEE
UNITED STATES SENATE

OVERSIGHT: EPA'S PROPOSAL FOR FEDERAL IMPLEMENTATION PLANS TO REDUCE INTERSTATE TRANSPORT OF FINE PARTICULATE MATTER AND OZONE

TESTIMONY OF CONRAD G. SCHNEIDER
ADVOCACY DIRECTOR, CLEAN AIR TASK FORCE

July 22, 2010

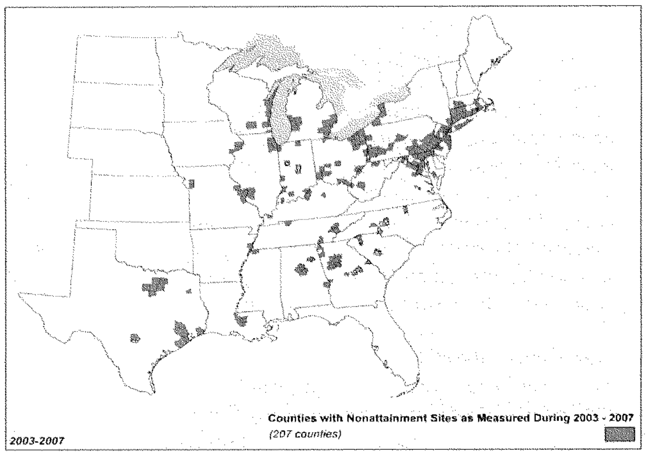
Summary of Testimony

Mr. Chairman, ranking member Vitter, members of the Clean Air Subcommittee of the Senate Environment and Public Works Committee, good morning. My name is Conrad Schneider, Advocacy Director of the Clean Air Task Force. I appreciate the opportunity to speak to you today. Based in Boston, the Clean Air Task Force is a national non-profit, environmental advocacy organization whose mission includes reducing the adverse health and environmental impacts of coal-fired electric generating plants. Our staff and consultants include scientists, economists, MBA's, engineers, and attorneys.

The first thing I want to do is bring you some good news regarding the substantial progress that has been made in reducing power plant sulfur dioxide pollution in the last five years. In 2004, sulfur dioxide emissions nationally were 11 million tons per year. Last year, they had fallen to 5.6 million tons. That is a cut of 50 percent in five years. The cause? A combination of: (1) New Source Review enforcement actions brought by EPA and several states that resulted in requiring sulfur scrubbers on power plants whose owners had illegally extended their useful lives without upgrading their emissions controls to meet Best Available Control Technology ("BACT"); (2) state regulations in nearly two dozen states that required older plants to install modern pollution controls; and (3) compliance with the Clean Air Interstate Rule's (CAIR) requirements. The economic recession did not cause the reductions. Installation of 130 scrubbers did. Health researchers estimate that reductions of this magnitude save tens of thousands of lives per year. And note that these reductions came without any noticeable increase in electricity prices, electricity bills, switching to natural gas, and without raising any reliability concerns whatsoever.

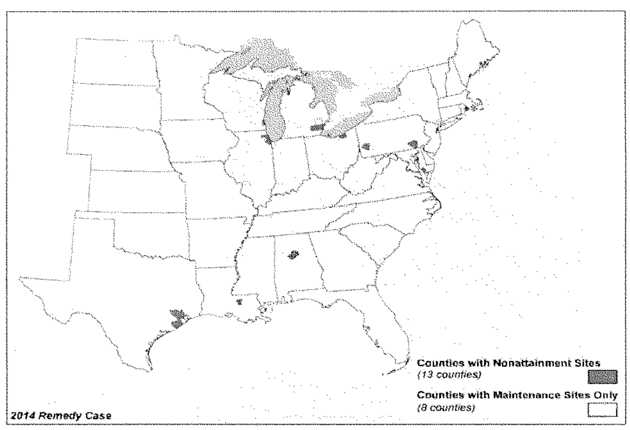
However, continued progress is now in jeopardy because the D.C. Circuit struck down the CAIR rule. Scrubbers have an operation and maintenance cost, so utilities will not run them unless they have to by law. But, even at today's pollution levels, tens of thousands of American lives will be cut short and there are still over 700 coal-fired units in the U.S. operating with no sulfur scrubber in place. It is high time that every coal-fired plant in the U.S. was well-controlled. That is why it is so important for EPA to strengthen and finalize the proposed Transport Rule. First, it will lock in the gains we have made in the last 5 years. Second, the Transport Rule goes further than CAIR in 15 states and brings many if not all nonattainment areas in the East into attainment. Senators Carper and Voinovich, as governors you used to see maps in which your states were full of red (nonattainment) counties. See Map A below.

Map A: Counties Violating Air Quality Standards in the Proposed Transport Rule Region (based on 2003-07 air quality monitoring data)



Under the EPA Transport Rule proposal, almost all the red is gone. See Map B below.

Map B: Counties with Monitors Projected to Have Ozone and PM2.5 Air Quality Problems in 2014 With the Proposed Transport Rule

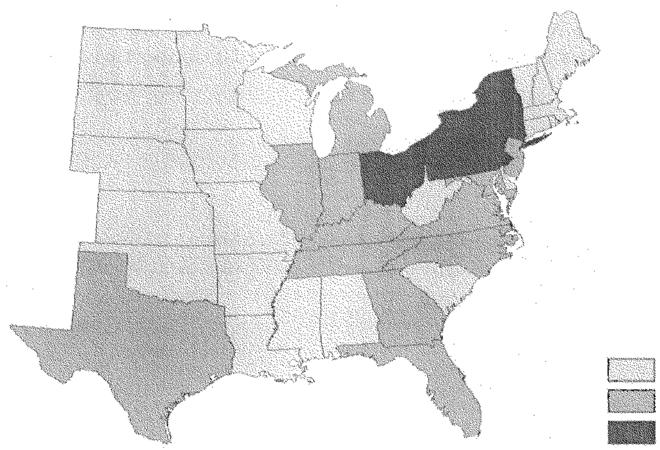


For those areas still projected to be in nonattainment in 2014 under the proposal, EPA has asked for comment on how to finish the job. CATF will be investigating that issue, but, in general, it appears that some tightening of the Transport Rule sulfur and nitrogen caps can "get the red out" completely.

At a minimum, EPA should complete the analysis it has begun relating to persistent nonattainment areas (wintertime daily PM2.5 areas, sulfur dioxide increases in Texas and Arkansas, and ozone nonattainment or maintenance issues in Houston, Baton Rouge, and New York City). Specifically, we call on EPA to identify sources upwind of persistent daily PM2.5 nonattainment in areas such as Cleveland and Chicago and require necessary additional scrubber installations. As proposed, the rule would require only 14 GW of additional scrubbers, so there is much more that can be done. In addition, EPA should tighten the summer NOx cap in the East and explore additional nitrogen oxide reductions that may be necessary to bring Houston and Baton Rouge into stable attainment with the ozone standard. These additional controls will be required to put those areas within striking distance so that local controls can get them to attainment.

Note that the "war between the states" – that is, between the Northeast and Midwest is largely over. All the states have realized that their pollution contributes to their neighbors' nonattainment. And, somewhat ironically (but not surprisingly), Ohio is among the biggest beneficiaries of the rule with 1,300 saved lives per year, the second most health benefits from the reductions next to Pennsylvania. See map below.

Benefits of Transport Rule by State



Mortality Avoided		Monetized Benefits (billion $)	
Low	High	Low	High
0 to 400	0 to 1,000	0 to 4	0 to 10
400 to 800	1,000 to 2,000	4 to 7	10 to 15
800 to 1,400	2,000 to 3,600	7 to 12	15 to 29

In addition to supporting EPA strengthening and finalizing the Transport Rule, CATF supports passage of S. 2995, the Clean Air Act Amendments of 2010 (CAAA of 2010). Although time in the current session of Congress is running out, CATF has long favored a comprehensive legislative solution to the problem of power plant pollution covering SO2, NOx, power plant toxics as well as carbon dioxide. In producing the proposed Transport Rule to replace the CAIR rule, EPA has done an admirable job in navigating the legal minefield laid for it by the D.C. Circuit. But, we know that just as the Bush CAIR rule was challenged and struck down, so a new set of power plant regulations may founder on the shoals of court challenges and delays. To guarantee the certainty of environmental improvement that the public health and the environment demand and the regulatory certainty that the electric power industry craves, Congress should act now to pass the steep reductions in the three power plant pollutants proposed by the CAAA of 2010.

Introduced on February 4, 2010, the proposed bill would codify stringent, national caps for sulfur dioxide and nitrogen oxides while providing a crucial "backstop" for EPA's regulatory process of setting maximum available control technology ("MACT") standards for power plant air toxics. The bill enjoys broad, bi-partisan support as it is co-sponsored by 9 Democrats, 5 Republicans, and one Independent.

A comparison between the emissions benefits of the proposed CAAA 2010 and EPA's proposed Transport Rule is instructive and demonstrates that the bill would achieve far greater reductions, particularly of sulfur dioxide emissions, and thus deliver greater air quality improvements and health-related benefits. In fact, although it outperforms the Transport Rule in emissions reductions and health benefits in every year, the CAAA of 2010 delivers lower system costs, lower electricity prices, and lower natural gas prices through 2020. CATF performed this analysis based on IPM data contained in EPA's Transport Rule proposal and analysis of the CAAA of 2010 as posted on its website and in the analysis of the bill requested by Senators Carper and Vitter by letter dated April 15, 2010 and provided by EPA on July 16, 2010.

Annual Sulfur Dioxide Emissions, Lives Saved, and Monetized Benefits under Transport Rule vs. CAAA of 2010

	2012	2015	2020	2025	Through 2025
No-CAIR emissions	9.5	8.5	8.4	8.4	121.4
TR emissions	4.8	4.1	4.1	4.0	59.4
CAAA 2010 emissions	3.9	3.4	2.9	2.1	45.3
TR emissions reduced	4.7	4.4	4.3	4.4	62.0
CAAA 2010 emissions reduced	5.6	5.1	5.5	6.3	76.1
TR lives saved	14,883	14,000	13,616	13,933	196,662

CAAA 2010 lives saved	17,773	16,150	17,416	19,950	241,099
CAAA 2010 lives saved over TR	2,890	2150	3,800	6,000	44,420
Valuation of CAAA 2010 over TR	$20 billion	$15 Billion	$27 billion	$42 billion	$312 billion

Importantly, EPA's analysis of the proposed CAAA of 2010 also demonstrates that passage of the bill would result in no noticeable increase in electricity or natural gas prices, no appreciable decrease in coal generation or use, or shifts in coal production or use within coal-producing regions. See table below based on EPA's modeling.

Costs, Electricity Prices, Natural Gas Prices, and Coal Generation under the Transport Rule and the CAAA of 2010 vs. No-CAIR Base Case

	Transport Rule				CAAA of 2010				TR vs. CAAA of 2010			
	2012	2015	2020	2025	2012	2015	2020	2025	2012	2015	2020	2025
Costs (B$2006)	3.7	2.7	2	2.1	-6	-3.3	3.3	5.8	-9.7	-6.1	1.2	3.8
Electricity Price Mills/kWh	3.4	.98	.94	.54	-8.7	-3.1	5.5	12.4	-12.1	-4.1	4.6	12
Natural Gas Price $/MMBtu	.11	.03	.01	.01	-.86	-0.1	.89	.81	-.97	-.13	.91	0.8
Coal Generation 1000 GWh	-9	-18	-15	-11	-67	-250	-403	-414	-57	-232	-388	-403

In its analysis, EPA also estimated the benefits of adopting a tighter nitrogen oxides cap in the east (.9 million tons per year v. 1.3 million tons per year). EPA's analysis suggests that the annual benefits of the tighter cap ($10 billion in 2025) outweigh the annual costs ($1.5 billion in 2025) while producing significant air quality improvements. This analysis should apply with equal force to the Transport Rule, which contains the identical eastern nitrogen oxides cap for a very comparable set of states. Accordingly, the sponsors of the proposed CAAA of 2010 should consider tightening the eastern nitrogen oxides cap during any mark-up of the bill and, similarly, EPA should tighten the nitrogen oxides caps when it finalizes the Transport Rule as EPA's own analysis demonstrates the significant benefits of doing so.

There has been a lot of discussion over the past couple of weeks about a possible Climate title to a Senate Energy bill. The focus now is on a power sector approach. Although, CATF has advocated for economy-wide coverage on a sector-by-sector basis in a Climate bill, given that the end of the session is drawing near, we support the efforts of senators and the White House to craft a meaningful power sector climate bill. However, some electric utilities apparently are asking that Clean Air Act requirements for non-greenhouse gas pollutants, like today's Transport Rule and next year's power plant toxics rule, be scrapped in exchange for a power sector-only climate bill. To this, we believe you should say "No Deal!" Congress in considering a Climate Bill should lay down a firewall to ensure that there are no Clean Air Act rollbacks with respect to power plant sulfur, nitrogen, or toxics emissions. We must continue to make progress in cleaning up the air as we address climate change and we should not trade off the right of our children to breathe clean air today for that of our grandchildren to inherit a planet without the ravages of global warming. Senator Alexander said it best when he said last week, ""You mean to spew more sulfur, nitrogen and mercury, and less carbon?" he said of such a deal. "That's not my idea of progress."--Sen. Lamar Alexander

Thank you and I would be happy to answer any questions.

Mr. Chairman, ranking member Vitter, members of the Clean Air Subcommittee of the Senate Environment and Public Works Committee, good morning, My name is Conrad Schneider, Advocacy Director of the Clean Air Task Force. I appreciate the opportunity to speak to you today. Based in Boston, the Clean Air Task Force is a national non-profit, environmental advocacy organization whose mission includes reducing the adverse health and environmental impacts of fossil-fuel electric generating plants. Our staff and consultants include scientists, economists, MBA's, attorneys and engineers.

Coal-fired electric power plants are by most measures the nation's largest industrial air polluter. Power plant emissions are the biggest contributor to the single largest environmental risk to public health: death and disease due to inhalation of fine particles. Power plant air emissions cut a broad swath of damage across human health, and the local, regional and global environment. Unhealthy levels of ozone smog; fine particles that shave years off peoples lives and damage lungs; the damage to forests, lakes, bays and crops due to Acid Rain; mercury contamination of fish and wildlife; shrouds of haze blanketing our national parks; contributions to greenhouse gasses; and groundwater contamination from the lack of proper disposal of solid and liquid waste from power plant fuel combustion – these are just some of the major environmental problems associated with the nation's fossil electric generating fleet.

The suite of pollutants from power plants: sulfur dioxide, nitrogen oxides, mercury and other air toxics, and carbon dioxide interact and operate synergistically to damage the environment. For example, global warming will likely increase the incidence and severity of summer smog episodes; acidification of water bodies mobilizes existing deposits of mercury meaning more mercury uptake into the food chain, etc. For these and other reasons (cost-effectiveness, planning certainty for industry, etc.) the problem of power plant pollution demands a comprehensive solution that coordinates the reduction of all four major power plant pollutants.

We commend EPA for its commitment, restated in today's testimony, that it intends to follow the requirements of the Clean Air Act and finalize a stringent Transport Rule as well as propose and finalize additional stringent power plant regulations to address residual nonattainment and significantly reduce power plant hazardous air pollutants. There is no question that EPA should promulgate stringent power plant regulations – including regulations on carbon dioxide consistent with EPA's statutory duty as expressed by the Supreme Court in *Massachusetts v. EPA*.[1] The recent D.C. Circuit decision in *New Jersey v. EPA*[2], vacating the Bush Administration's power plant CAMR rules and other recent D.C. Circuit precedents interpreting the Maximum Available Control Technology (MACT) provision of the Act draw a clear road map for the Agency to set stringent MACT standards for power plant hazardous air pollutants (HAPs).[3] By contrast, the decision in *North Carolina v. EPA* striking down the Clean Air Interstate Rule (CAIR) presents a minefield of legal and technical obstacles that leave EPA's regulatory way forward far less clear.[4] In producing the proposed Transport Rule to replace the CAIR rule, EPA has done an admirable job in navigating that legal minefield. Upon our preliminary review, CATF believes EPA may have proposed a workable framework for detecting and remedying "significant contribution" by upwind sources on downwind nonattainment areas, although it seems likely that adopting the "direct control" option that forbids interstate trading would reduce the litigation risk associated with the rule. We know that just as the Bush CAIR and CAMR rules were challenged and struck down, so a new set of power plant regulations may founder on the shoals of court challenges and delays. To guarantee the certainty of environmental improvement that the public health and the environment demand and the regulatory certainty that the electric power industry craves, Congress should act now to pass steep reductions in these three power plant pollutants as proposed by the CAAA of 2010.

So, in addition to supporting EPA strengthening and finalizing the Transport Rule, CATF supports passage of S. 2995, the Clean Air Act Amendments of 2010 (CAAA of 2010). CATF has long favored a comprehensive legislative solution to the problem of power plant pollution. While stringent, comprehensive legislative action on power plant pollution would be ideal, CATF also recognizes that the time window for legislative action in the current session of Congress is rapidly closing; therefore, CATF fully supports EPA's efforts to move forward with a strengthened Transport Rule and the other power plant rules that EPA is committed and legally obliged to issue.

CATF opposes a so-called technical "fix" which would give EPA the authority to allow emissions trading in the replacement rule for CAIR without at the same time setting specific emissions caps and dates for sulfur dioxide and nitrogen oxides reductions. The reductions envisioned in the CAIR rule were "too little, too late" to address fully the public health and environmental impacts caused by power plant nitrogen oxides and sulfur dioxide. CATF would also note that the old "war between the states" i.e., between the Northeast vs. the Midwest and Southeast, is largely over. States in each of these regions now agree that deeper reductions than those contained in CAIR will be needed to bring their areas into attainment with ozone and particulate matter air quality standards.

The cost of this bill (see discussion infra) is not too much to pay to save tens of thousands of lives per year, clear the vistas in our national parks, help restore the health of our forests and lakes, cut summer ozone smog, and virtually eliminate the power sector's contribution to mercury contamination in our fish. CATF submits that this represents a small price to pay and many years overdue.

CATF commends the House of Representatives for passing economy-wide climate change legislation which, if enacted, would result in reductions in power sector carbon dioxide. Power plants are the single largest source of CO2 emissions in the United States, representing 41 percent of all CO2 emissions.[5] But, even enactment of the comprehensive carbon dioxide legislation will not appreciably reduce power plant sulfur dioxide, nitrogen oxides, or mercury emissions. This is because bills like Waxman-Markey and Kerry-Lieberman do not target these emissions and will not result in the curtailment or shutdown any appreciable number of coal plants for the foreseeable future. Only installation of specifically-targeted pollution controls – e.g., flue gas desulfurization for sulfur dioxide and acid gas control, selective catalytic reduction for nitrogen oxide emissions, and the addition of activated carbon injection to these technologies for mercury reduction – can result in the level of pollution reductions necessary to achieve the reductions that public health and the environment demand. And, if under a climate bill existing coal plants are to be retrofitted with post-combustion controls for carbon dioxide capture, it appears that they must virtually eliminate their sulfur, nitrogen, and mercury emissions for those carbon dioxide controls to function properly

Because this hearing is focused on the pollutants addressed in the proposed Transport Rule i.e., sulfur dioxide and nitrogen oxides, CATF will confine our testimony today to the public health, environmental science, and public policy imperatives to reducing the power sector's share of these two pollutants. CATF's views on the necessity of regulating carbon dioxide and other greenhouse gases are expressed in our comments on EPA's proposed "endangerment finding" filed on June 23, 2009[6] and power sector hazardous air pollutants (HAPs) in my July 9, 2009 testimony before this Subcommittee.[7]

The best science available demonstrates the need for steep cuts in these pollutants and the technical feasibility of achieving these reductions:

- National reductions in power plant emissions of sulfur dioxide down to 1.5 million tons per year;
- National reductions in power plant emissions of nitrogen oxides down to 1.2 million tons per year;

I will address the impacts from each of these pollutants in turn and discuss the science that supports these reduction targets:

Sulfur Dioxide

The problems associated with sulfur dioxide include: deadly fine particles, damage from Acid Rain, and the haze that obscures scenic vistas in national parks and our urban areas. Power plants emit about two-thirds of the sulfur dioxide emitted in the U.S. each year.

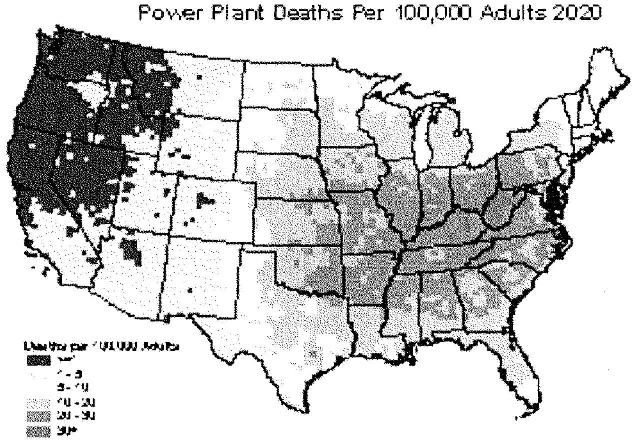
A 1.5 Million Ton Per Year Sulfur Dioxide Emissions Cap will Avoid Tens of Thousands of Particulate-Related Premature Deaths Each Year

The most deadly pollutant resulting from power plant emissions is fine particulate matter. Fine particles, such as those that result from power plant sulfur and nitrogen emissions, defeat the defensive mechanisms of the lung, and can become lodged deep in the lung where they can cause a variety of health problems. EPA's latest review of the scientific literature indicates that short-term exposures can not only cause respiratory (e.g., triggering asthma attacks), but also cardiac effects, including heart attacks.[8] In addition, long-term exposure to fine particles increases the chances of death, and has been estimated to shave years off the life expectancy of people living in our most polluted cities, relative to those living in cleaner ones.[9]

Fine particulate matter may be emitted directly from tailpipes and smokestacks (known as "primary" particulate matter), but the largest proportion of fine particles come from gaseous emissions (called "secondary" particulate matter). Sulfur dioxide emissions from coal plants contribute the most to secondary particle formation. Sulfur dioxide is chemically altered in the atmosphere after it is released from a smokestack to become a "sulfate" particle. Sulfates include sulfuric acid particles that, when breathed, reach deep into the human lung. Indeed, analysis of the relative toxicity of particles indicates that sulfate particles are among the most toxic.[10] In the East and Midwest U.S., sulfate makes up the largest proportion of the particles in our air—in many regions well over half of the fine particles. Moreover, power plants currently emit two thirds of the sulfur dioxide in the U.S. Therefore, to reduce particulate matter, major reductions in pollution emissions from fossil-fuel power plants are needed.

Thus, the evidence is clear, and has been confirmed independently, fine particle air pollution, and especially those particles emitted primarily by fossil-fuel power plants, are adversely affecting the lives and health of Americans. The importance of these particulate matter-health effects relationships is made clear by the fact that virtually every American is directly impacted by this pollution. People living in the Midwest and Southeast, where the greatest concentrations of coal-fired power plants are located, face the greatest risk. See map below.[11]

Power Plant Deaths Per 100,000 Adults 2020

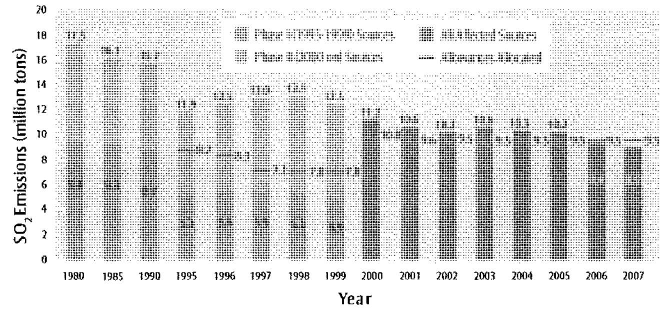


In addition, work by researchers at the Harvard School of Public Health found that the risk from power plant pollution is not evenly distributed geographically.[12] The risk was found to be greatest in relatively close proximity to the power plants: people living within 30 miles of a plant were found to face a risk of mortality from the plant's emissions 2-3 times greater than people living beyond 30 miles do.[13] These "local" impacts suggest that a national "cap and trade" program that allows some plants to escape pollution controls through the purchase of emission credits will not reduce the specific risk posed by those emissions to the surrounding population. This work supports the need for the "birthday bill" provision that requires each facility to meet modern pollution standards by a date certain. In the Transport Rule, this can be achieved by EPA choosing the finalizing the "direct control" option, which will assure plant-specific emission reductions.

Only a 1.5 Million Ton Per Year Sulfur Dioxide Cap Will Allow Ecosystem Recovery from Acid Rain by Mid-Century

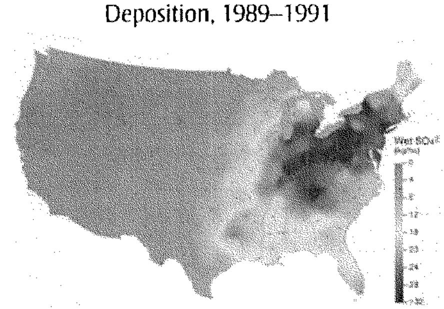
Although sulfur dioxide emissions have been reduced significantly since 1980 through the 1990 Clean Air Act Amendment's Acid Rain program, the program has now surpassed its emissions target[14] – a level that scientists say is far higher than the level necessary to allow for full ecosystem recovery in the Adirondacks and Southern Appalachian mountains.

Figure 2: SO_2 Emissions from Acid Rain Program Sources



Source: EPA 2008

Annual Mean Wet Sulfate Deposition, 1989–1991



Source: NADP, 2008

Annual Mean Wet Sulfate
Deposition, 2005–2007

Source: NADP, 2008

It is increasingly well-documented that the problem of Acid Rain has not been solved and that the Acid Rain provisions of the 1990 Clean Air Act Amendments will not be sufficient to solve it. Over 150 years of deposition of sulfur has taken a serious toll on ecosystems. Although sulfur emissions have declined in recent years, they remain very high when compared to historic levels.[15,16,17,18,19]

As a result of this legacy, lakes and streams and the aquatic life that live in them are experiencing the most widespread impact from high concentrations of acidity. The majority of sensitive water bodies are those that are located atop soils with a limited ability to neutralize (or buffer) acidity. Sensitive areas in the U.S. include the Adirondack Mountains, Mid-Appalachians, southern Blue Ridge[20] and high-elevation western lakes.[21] Water bodies are affected not just by the chronic acidification that occurs from cumulative deposition but also by episodic acidification that occurs when pulses of highly acidic waters rush into lakes and streams during periods of snowmelt (from acids that have collected in the snow over the winter) and heavy downpours.

In some places, chronic and episodic acidification together have completely eradicated fish species. For example, acid-sensitive fish have disappeared and/or populations have been reduced in Pennsylvania streams where they formerly occurred in large numbers. Acidification, together with high levels of aluminum leaching, is blamed for the reduction in fish diversity that many Pennsylvania streams have experienced over the past 25-34 years.[22]

Acidic deposition has impaired, and continues to impair, the water quality of lakes and streams in the eastern U.S. in three important ways: lowering pH levels (i.e., increasing the acidity); decreasing acid-neutralizing capacity (ANC); and increasing aluminum concentrations. Many surface waters in New England, the Adirondack region of New York, and the Northern, Central and Southern Appalachian Mountain regions exhibit chronic and/or episodic (i.e., short-term) acidification. Moreover, elevated concentrations of dissolved inorganic aluminum have been measured in acid-impacted surface waters throughout the East. [23,24,25,26,27]

Damage to Freshwater Marine Ecosystems

High concentrations of aluminum and increased acidity have reduced the species diversity and abundance of aquatic life in many lakes and streams draining acid-sensitive regions in the East. Fish have received the most attention to date, but entire food webs are often negatively affected. For example, in a survey of lakes in the Adirondacks, 346 lakes (24 percent of the total) did not contain fish. These fishless lakes had significantly lower pH and higher concentrations of dissolved inorganic aluminum when compared to those lakes with fish. [28,29,30,31,32,33].

There are important linkages between acidic deposition and other water quality problems. For example, mercury contamination of fish is coupled to surface water acidification through a pattern of increases in fish mercury concentration with decreases in surface water pH. Studies across the eastern U.S. have shown that many surface waters have elevated concentrations of mercury in fish tissue as a result of atmospheric emissions and deposition of mercury. "Biological mercury hotspots" have been identified at five areas in eastern North America.

Emissions targets set in the U.S. thus far have been met or exceeded. Decreases in sulfate have been measured at monitoring sites throughout the Northeast U.S., although many sites in the Southeast U.S. are still showing increases in sulfate deposition. Where there are declines, improvements in acid-base chemistry have also been measured. Fish populations in marginally affected lakes are recovering. Unfortunately, no improvements have been observed in lakes that have been more seriously and chronically impacted by acidification, indicating that deeper cuts are needed. [34,35,36]

Damage to Forest Ecosystems

Acidic deposition has altered, and continues to alter, forest soil by accelerating the leaching of calcium and magnesium and increasing concentrations of dissolved inorganic aluminum in soil waters. At high concentrations, dissolved inorganic aluminum can hinder the uptake of water and essential nutrients by tree roots.

The alteration of soils by acid deposition has serious consequences for acid-sensitive forest ecosystems. Soils that are compromised by acidic deposition are less able to neutralize additional inputs of strong acids, and provide poorer growing conditions for plants and delay the recovery of surface waters. [37,38,39,40,41].

Experimental additions of calcium in terrestrial sites, which mimics reduced acidifying deposition, show that recovery can be achieved. Modeling exercises conducted for three affected watershed in the Northeast US show that at the levels of reductions called for in the CAAA of 2010, chemical conditions would approach recovery thresholds by mid-century. [42,43,44].

What Will it Take to Solve the Problem?

In summary, it is well documented that surface waters in New England, the Adirondacks, and the Northern, Central and Southern Appalachian mountain regions have been adversely impacted by elevated inputs of atmospheric sulfur and nitrogen deposition. Surface waters in these areas exhibit chronically acidic conditions or have low values of acid neutralizing capacity, which make them susceptible to short-term episodic acidification.

The modest decreases in sulfate concentrations and increases in pH and acid neutralizing capacity exhibited in some surface waters is an encouraging sign that impacted ecosystems are responding to emission controls and moving toward chemical recovery. Nevertheless the magnitude of these changes is small compared to the magnitude of increases in sulfate and decreases in acid neutralizing capacity that have occurred in acid-impacted areas following historical increases in acidic deposition.

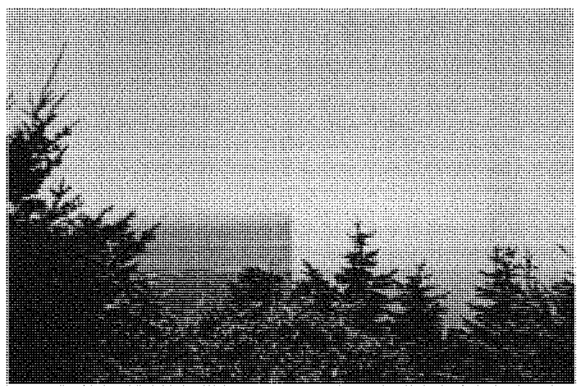
Despite declines in power plant sulfur emissions due to Acid Rain provisions of the 1990 Clean Air Act amendments, the acidity of many water bodies has not improved.[45] Scientists believe that cuts called for in the 1990 amendments to the Clean Air Act will not be adequate to protect surface water and forest soils of the northeastern U.S.[46]

What will it take to reverse the impacts of nitrogen saturation, ozone and Acid Rain? Work by scientists with the Hubbard Brook Research Foundation found that an additional 80 percent reduction in sulfur from levels achieved by Phase II of the Acid Rain program of the Clean Air Act Amendments of 1990 would be needed to allow biological recovery to begin by mid century in the Northeastern U.S.[47] Model simulations in the Shenandoah project that greater than 70 percent reduction in sulfate deposition (from 1991 levels) would be needed to change stream chemistry such that the number of streams suitable for brook trout viability would increase. A 70 percent reduction would simply prevent further increase in Virginia stream acidification.[48] In the Great Smoky Mountains National Park, two separate ecosystem models have concluded that sulfate reductions of 70 percent are necessary to prevent acidification impacts from increasing. Deposition reductions above and beyond these amounts are necessary to improve currently degraded aquatic and terrestrial ecosystems.[49,50] The Title IV Acid Rain cap under the current Clean Air Act is 8.9 million tons per year.

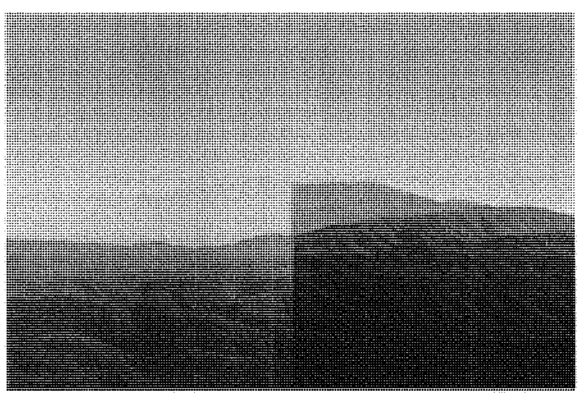
Meeting a 1.5 million ton per year sulfur dioxide cap that would represent the 75 to 80 percent reduction from current Title IV targets is a precondition for recovery to get a foothold by mid-century. Make no mistake about it; there is no time to waste. Even with deep reductions irreversible damage has already occurred. It will take acid waters many decades to recover once acid inputs are reduced to close to pre-industrial levels; soils and water bodies will take centuries to recover. While recovery may be slow, maintaining emissions at today's level will mean even more irreversible damage and even a longer wait before improvement can be measured. Even tighter targeted cuts may be necessary for sources directly impacting sensitive areas. And, the longer we wait for the reductions to begin, the longer we will await recovery of these precious systems.

A 1.5 Million Ton Per Year Sulfur Dioxide Cap will be Necessary to Regain Pristine Vistas in our National Parks and Wilderness Areas

In the last several decades, visibility – how far you can see on an average day – has declined dramatically, especially in the Eastern half of the United States. In the East, annual mean visibility is commonly one quarter of natural conditions and as little as one-eighth in the summer. One of the greatest casualties of this upsurge in regional haze has been the national parks. Examples of the magnitude of visibility decline due to high air pollution levels are shown below in Acadia National Park and the Great Smoky Mountains National Park. These are actual photographs of vistas in those parks taken on clear days and days on which sulfate particulate matter levels were high.



Acadia National Park on a Clear and a Polluted Day



Great Smoky Mountains National Park on a Polluted and a Clear Day

There is no question that power plants are the major driver of this problem: visibility impairment has tracked closely in parallel with sulfate and electric power production for nearly half a century. Taken together, sulfur, carbon and nitrogen oxide emissions are responsible for about well over 80 percent of this visibility impairment. When these components are assessed for their contribution to the problem, electric power is accountable for about two-thirds of the emissions that lead to regional haze-related visibility impairment in the East, most of which is caused by sulfate.

Half-measures will not solve the problem of visibility impairment in our nation's parks. EPA has set a long-term goal of eliminating man-made haze by 2060. That goal will never be achieved without steeply cutting power plant emissions consistent with the 1.5 million ton per year reduction target in the CAAA of 2010. Indeed, the cuts in sulfur dioxide to date under the Acid Rain program have not led to perceptibly improved vistas. Research shows that visibility improves more rapidly with deeper cuts in sulfate. Thus, we will achieve pristine views in those areas shrouded in a sulfate haze only when the deepest cuts in sulfur dioxide emissions have been achieved.

There is concern about haze from other quarters as well. Research is showing that both haze and particulate matter are depressing optimal yields of crops.[51] Yield decreases in the northeastern United States are estimated to be occurring in the 5 – 10 percent range. In the southeast the decrease in optimal yields for summertime crops is likely higher — about 10–15 percent.

Nitrogen Oxides

The problems associated with nitrogen oxides include the massive health and ecosystem damage due to ozone smog and nitrogen deposition. Power plants are responsible for about one-quarter of the nitrogen oxides emitted in the U.S. each year.

Ground level ozone is a colorless, odorless pollutant that causes respiratory damage ranging from temporary discomfort to long-term lung damage. According to a recent study[52], in the Eastern half of the United states, ground level ozone sends an estimated 159,000 people to emergency rooms each summer; triggers 6.2 million asthma attacks, and results in 69,000 hospital admissions. Many more millions of Americans experience other respiratory discomfort.

Although much of the controversy around ground level ozone in recent years has centered on ozone levels in the Northeast, and the impact of Midwest and Southern emissions on the Northeast, this misses an important part of the story: ***many Midwestern and Southeastern states suffer greater ozone exposures and per capita health impacts than many Northeast states.*** According to a study by the Ohio Environmental Council, in collaboration with the University of Michigan and Harvard University,[53] people in Ohio River Valley communities such as Cincinnati and Marietta, Ohio are often exposed to dangerous levels of ground level ozone as much as 75 percent ***more*** than people in Boston and New York. Ohio River Valley ozone hospital admission rates also track this pattern – with admission rates higher in the Ohio Valley than in the East.

The reason is not hard to discern. There is a high correlation between elevated ground level ozone and proximity to power plants – especially in the Midwest and Southeast where roughly 60 percent of the nation's coal-fired generating capacity is located. In the Ohio Valley area studied, emissions from coal- and oil-fired power plants contribute nearly ***fifty percent*** of elevated ozone levels in the Valley, enough by themselves to cause violations of the federal health standard.[54] Partly out of recognition of this in-region problem, the decades old "war between the states" i.e. the Northeast v. the Midwest and Southeast, is largely over. Today, states in each of these regions recognize that deeper reductions in nitrogen oxides emissions than those contained in the CAAA of 2010 will be necessary to bring their areas into attainment with the new ozone standards.

Crop Losses Due to Ozone Smog

Human health is not smog's only victim. There is strong scientific evidence showing that current levels of ground level ozone are reducing yields, particularly in sensitive species — soybean, cotton, and peanuts from National Crop Loss Assessment Network (NCLAN) studies. Annual crop loss from ozone for soybeans alone in Illinois, Indiana and Ohio has been calculated to fall between $198,628,000 – 345,578,000. Ozone-induced growth and yield losses for the seven major commodity crops in the Southeast (sorghum, cotton, wheat barley, corn, peanuts and soybeans) are costing southeast farmers from $213-353 million annually.[55]

Year-Round Reductions of Nitrogen Oxides will be Necessary to Minimize the Effects of Nitrogen Deposition

Power plant nitrogen emissions deposited on land and water — sometimes at great distances from their original sources —is an important contributor to declining water quality.[56] Estuarine and coastal systems are especially vulnerable. Too much nitrogen serves as a fertilizer, causing excessive growth of seaweed. The result is visual impairment and loss of oxygen. With the loss of oxygen, many estuarine and marine species — including fish — cannot survive.[57]

The contribution of nitrogen from atmospheric deposition varies by watershed. In the Chesapeake Bay, atmospheric nitrogen accounts for 27 percent of nitrogen entering the system.[58] Of that amount, power plants account for about a third.

Nitrogen is also being deposited on ocean surfaces many, many miles away from land. Atmospheric nitrogen accounts for 46 to 57 percent of the total externally supplied (or new nitrogen) deposited in the North Atlantic Ocean Basin.[59]

Reductions Appropriate In Federal Policy

In each of the above areas, the best scientific evidence calls for steep reductions in power plant pollution:

- In the case of sulfur dioxide, capping power plant emissions nationally at 1.5 million tons per year will save tens of thousands of lives per year.
- In addition, reductions in power plant sulfur dioxide emissions at least this deep are a precondition to ecosystem recovery from Acid Rain while dividends in the form of fine particle reduction and reduced haze will result as well.
- In the case of nitrogen oxides, ozone smog health impacts and air quality standard violations will be dramatically reduced by capping emissions of nitrogen oxides at 1.2 million tons per year as will year round nitrogen and Acid Rain impacts.

Fortunately, the technology is at hand to dramatically reduce these power plant emissions and their resultant impacts throughout the nation, at reasonable costs. For example:

- Power sector reductions of sulfur dioxide down to 1.5 million tons per year are readily achievable through a combination of flue gas desulfurization (scrubbing), use of cleaner fuels, and greater commitment to energy efficiency and renewable resources.
- Year round nitrogen reductions down to a cap of 1.2 million tons per year are achievable through selective catalytic and non-catalytic reduction technology, low NOx burners, overfire air, and use of cleaner fuels, and greater commitment to energy efficiency and renewable resources.

Historical Summary of Regulation of Transported Air Pollutants in the East and Midwest

Congress and EPA have been attempting to deal with the problem of transported air pollution across state boundaries in the eastern part of the country for over 30 years. Progress has been made, but it has been slow, and much more work is still needed.

The air pollution transport problem was initially recognized in connection with Acid Rain pollution and Congress responded with Title IV of the Clean Air Act Amendments of 1990. That statute also recognized that ground-level ozone is a regional, and not merely a local, problem. Ozone and its precursors (most importantly, nitrogen oxides or NOx emitted in the warmer months) may be transported long distances across state lines, thereby exacerbating ozone problems downwind. For several decades, ozone transport has been recognized as a major reason for the persistence of the ozone problem, notwithstanding the imposition of numerous controls, both federal and state, across the country. The same transport problem has also been more recently recognized in the context of fine particulate ($PM_{2.5}$) pollution.

The 1977 Amendments to the Clean Air Act (the Act) included two provisions focused on interstate transport of air pollutants: the predecessor to current section 110(a)(2)(D) and section 126. In the 1990 Amendments, Congress strengthened these two provisions to better address interstate transport of air pollutants. Section 110(a)(2)(D)(i)(I) generally requires that state implementation plans (SIPs) for nonattainment areas include adequate provisions prohibiting emissions that contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS. If states do not submit SIPs in a timely or approvable manner, EPA has the authority to make findings of failure to submit or impose FIPs on specific sources in the state that contribute to downwind nonattainment and interference with maintenance. Section 126 authorizes a downwind state (or subdivision) to petition EPA to impose limits directly on upwind sources found to emit pollutants contribute significantly to nonattainment in, or interfere with maintenance by, that state.

The 1990 Amendments also added section 184, which delineated a multi-state ozone transport region (OTR) in the Northeast, required specific additional controls for all areas in that region, and established the Ozone Transport Commission (OTC) for the purpose of recommending to EPA regionwide controls affecting all areas in that region. In 1994, the Northeast OTC states signed a Memorandum of Understanding (MOU) committing to reduce ozone-producing NOx emissions throughout the region. In 1999 through 2002, most of the OTC states achieved substantial NOx reductions through an ozone season cap and trade program for NOx called the OTC NOx Budget Program and administered by EPA, and through NOx emission rate limits from certain coal plants under Title IV of the Act.

Section 126 Petitions

As the initial set of ozone deadlines in the 1990 CAAA approached in the mid-1990's, states at the "end of the tailpipe" of pollution in the eastern U.S. such as Maine and New Hampshire realized that the Clean Air Act set attainment deadlines that preceded those of states upwind of them meaning that those upwind states would not be required to deliver pollution reductions in time to eliminate their significant contribution to their downwind neighbors. Through air quality modeling analysis, Maine and New Hampshire found that they could eliminate their in-state emissions of ozone precursors and still not demonstrate attainment due to pollution transported over the border. While they contemplated pressing "overwhelming transport" petitions seeking relief from all CAA requirements, both states chose the more constructive course of action, filing section 126 petitions rather than face sanctions for failing to file approvable SIPs on time. Notably, Maine and New Hampshire's 126 petitions named not only coal-fired power plants in the Ohio River Valley, they named sources in every intervening state in the Northeast, setting off a "cascade" of eight 126 petitions by the Northeastern states against each of their upwind neighbors as well as against several Midwestern and Southeastern states. EPA proposed action on petitions submitted by the eight northeastern states in 1997 under section 126 of the Act. Each petition specifically requested that EPA make a finding that NOx emissions from certain major stationary sources significantly contributed to ozone nonattainment problems in the petitioning state.[60]

In 1999, EPA partially granted four of those petitions, ruling that electric power plants and other major stationary sources in 13 eastern states were in violation of section 126 and required reductions of NOx emissions of about 500,000 tons (64 FR 28250). However, EPA effectively structured the 126 remedy as a backstop for the NOx SIP Call by limiting its application to affected sources only in the event that EPA failed to finalize the SIP Call trading program. Because EPA eventually implemented the NOx SIP Call trading program, the section 126 default remedy was never actually applied.[61] Industry's federal court attack on EPA's section 126 rulemaking was largely rejected in Appalachian Power Co. v. EPA, 249 F.3d 1032 (May 15, 2001).

OTAG

Separate from the activity in the OTC, EPA and the Environmental Council of the States (ECOS) formed the Ozone Transport Assessment Group (OTAG) in 1995. This workgroup brought together interested states and other stakeholders, including industry and environmental groups (including CATF). Its primary objective was to assess the ozone transport problem and develop a strategy for reducing ozone pollution throughout the eastern half of the United States.

Notwithstanding significant efforts, the states generally were not able to meet the 1994 statutory deadline for the ozone attainment demonstration and rate of progress (ROP) SIP submissions required under section 182(c) of the Act. The major reason for this failure was that at that time, states with downwind nonattainment areas were not able to address transport from upwind areas. Development of the necessary technical information, as well as the control measures necessary to achieve the large level of reductions likely to be required, was particularly difficult for the states affected by ozone transport.

In response, as an administrative remedial matter, EPA established new timeframes for the required SIP submittals. To allow time for states to incorporate the results of the OTAG modeling into their local plans, EPA extended the submittal date to April 1998. The OTAG's air quality modeling and recommendations formed the basis for what became the NOx SIP Call rulemaking and included the most comprehensive analyses of ozone transport ever conducted. The EPA participated extensively in the OTAG process that generated substantial technical and modeling information on the nature and extent of regional ozone transport.

NOx SIP Call

NOx SIP Call

Based on the findings of OTAG, EPA proposed a rulemaking known as the NOx SIP Call in 1997 and finalized it in 1998 (63 FR 57356). EPA concluded in this rule that NOx emissions in 22 eastern states and the District of Columbia contributed significantly to ozone nonattainment in other downwind states, and required those jurisdictions to revise their SIPs to include NOx control measures to mitigate the significant ozone transport during the summer ozone season (May-September). The EPA established emissions reduction requirements for the covered states and source categories, which essentially established a cap on ozone season NOx emissions in the state. In total, states in the region were required to reduce ozone season NOx by about 1 million tons (representing about a 25% reduction). The affected states were required to submit SIPs providing the specified amounts of emissions reductions. By eliminating these amounts of NOx emissions, EPA concluded that the control measures would assure that the remaining NOx emissions would meet the level identified in the rule as the state's NOx emissions budget and would not "significantly contribute to nonattainment, or interfere with maintenance by," a downwind state, under section 110(a)(2)(D)(i)(I). The SIP requirements permitted each state to determine what measures to adopt to meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve decreased NOx emissions primarily from large stationary sources in a trading program, EPA encouraged states to consider electric utility and large boiler controls under a cap and trade program as a cost-effective strategy.

The NOx SIP Call was EPA's principal effort to reduce interstate transport of precursors for both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS. The EPA's rulemaking was based on its consideration of OTAG's recommendations, as well as information resulting from EPA's additional work, and extensive public input generated through notice-and-comment rulemaking. EPA has indicated that it believed that requiring NOx emissions reductions across the region in amounts achievable by uniform controls was a reasonable, cost-effective step to take to mitigate ozone nonattainment in downwind states for the ozone standards. It was also EPA's stated goal to ensure that sufficient regional reductions were achieved to mitigate ozone transport in the eastern half of the United States and thus, in conjunction with local controls, enable nonattainment areas to attain and maintain the ozone NAAQS.

In response to litigation over EPA's final NOx SIP Call rule, the federal Court of Appeals for the DC Circuit issued two decisions concerning the NOx SIP Call and its technical amendments. See Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000), cert. denied, 532 U.S. 904(2001) (SIP Call); and Appalachian Power v. EPA, 251 F.3d 1026 (D.C. Cir. 2001) (technical amendments). The Court decisions generally upheld the NOx SIP Call and technical amendments, including EPA's interpretation of the definition of "contribute significantly" under CAA section 110(a)(2)(D). The litigation over the NOx SIP Call coincided with the litigation over the 8-hour NAAQS, and due to the uncertainty caused by the latter litigation, EPA stayed the portion of the NOx SIP Call based on the 8-hour NAAQS (65 FR 56245, September 18, 2000). That stay remains in effect, and thus the NOx SIP Call does not address attainment and maintenance problems under the 8-hour ozone standard.

Results

The NOx SIP Call has been a success by any number of measures. Compliance has been almost 100 percent. Prices for 2008 vintage NOx allowances have dropped from a high in 2003 of about $3000/ton at the beginning of the program to a low of $592/ton in 2008. EPA figures show a 43 percent drop in ozone season NOx emissions in the control region from 2003 to 2008 (some of which are likely due to controls installed in anticipation of CAIR, discussed below), while regional ozone levels have shown a 10-14 percent drop. These ozone reductions, combined with $PM_{2.5}$ reductions due to lower NOx emissions, saved an estimated 580-1,800 lives in 2008.

Despite these improvements, ozone levels remained stubbornly high, and many areas continued to be in nonattainment. Furthermore, the NOx SIP Call did not address the problem of transported fine particulates ($PM_{2.5}$) and their precursors, and in 2004 many areas remained in nonattainment of the 1997 PM2.5 NAAQS.

NSR Enforcement Actions

Throughout the 1970's, the State of New York was the focus of concerns about power plant pollution stemming mostly from the discovery of the ecosystem damage caused by Acid Rain in the state's Adirondack Mountains, most of which was attributable to upwind power plant emissions of sulfur dioxide and nitrogen oxides. When it became clear that the Acid Rain program in the Clean Air Act Amendments of 1990 (Title IV) would not deliver sufficient pollution reductions to allow the damaged ecosystems to recover and with new concerns raised by nonattainment with federal particulate matter and ozone ambient air quality standards (also driven in significant part by upwind power plant emissions) and related Clean Air Act deadlines, New York State began to look for other means of reducing transported pollution. Beginning in 1999, the New York Attorney General's office initiated enforcement actions against utility companies owning coal-fired power plants in states upwind of New York as well as in-state power companies for violations of the Clean Air Act's New Source Review provisions. In parallel, after years of investigation, EPA and the U.S. Department of Justice launched the federal Coal-Fired Power Plant Enforcement Initiative.[62] Both EPA and New York had discovered that many power companies had made "major modification(s)" of their electric generating units without upgrading their emissions controls to meet Best Available Control Technology ("BACT") as required by the New Source Review provisions of the Clean Air Act. Some of the enforcement actions were settled via consent order while others were contested and went to trial. Today, notices of violation and administrative orders cover 32 plants in 10 states and have led to unit-specific requirements for dozens of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) installations. CATF worked closely with the New York Attorney General's office to support the original initiative and intervened in several of the federally filed actions including the American Electric Power and Cinergy cases. CATF also helped challenge the Bush Administration's efforts to shield power company misbehavior by weakening the regulations governing the applicability of New Source Review to existing plants. Most of those challenges were successful in limiting damage to the program.

State Power Plant Regulations and Legislation

From its inception in 1996, CATF has advocated for state-level policies to require the clean up of power plant pollution with an initial focus on reducing sulfur dioxide and nitrogen oxides emissions. As a result of our efforts and those of affiliated campaigns, over 20 states have adopted multi-pollutant power plant limits via regulation and/or legislation.[63] Many of these provisions have set the bar for achievable sulfur dioxide, nitrogen oxides, and mercury reductions from existing coal plants. For sulfur dioxide, almost all of them require the installation of flue gas desulfurization either as a direct requirement or through emissions limits and caps that have been met via scrubbing –

since 2004 these state requirements have led to the installation of nearly three dozen FGD installations.

Clean Air Interstate Rule (CAIR)

As a presidential candidate, George W. Bush promised to support a multi-pollutant solution to power plant pollution, including limits on power plant carbon dioxide. However, shortly after his inauguration, Bush abandoned his pledge on carbon dioxide and, through a series of meetings held by Vice-President Cheney with the energy industry, the Administration devised a plan to gut existing Clean Air Act authorities and replace them with a watered-down legislative alternative dubbed "Clear Skies". When by 2005, after intense opposition by the environmental community, including CATF, and many states it became clear the "Clear Skies" had no chance of passage by Congress, the Bush Administration EPA promulgated a series of regulations modeled on "Clear Skies" – the "Clean Air Interstate Rule ("CAIR"), the "Clean Air Mercury Rule" ("CAMR"), and the "Clean Air Visibility Rule" ("CAVR") -- and moved to adopt via regulation the rollbacks of the New Source Review program for existing sources. EPA promulgated the Clean Air Interstate Rule ("CAIR") on May 12, 2005 (70 FR 25162), finding that emissions in certain upwind states resulted in amounts of transported PM2.5, ozone, and their emissions precursors that significantly contributed to nonattainment in downwind states. Those findings were accompanied by air quality modeling, ambient air quality data analyses, and cost analyses.

CAIR required SIP revisions in 28 states and the District of Columbia to prohibit certain emissions of SO2 and/or NOx. EPA decided that achieving the emissions reductions identified would address the states' requirements under section 110(a)(2)(D)(i)(I) of the Act and would help PM2.5 and ozone nonattainment areas in the eastern half of the United States attain the standards. EPA noted that additional local reductions might be necessary to bring some areas into attainment even after significantly contributing upwind emissions were eliminated. EPA concluded that attainment would be achieved in a more certain, equitable, and cost-effective manner with a combination of upwind and local emissions reductions.

CAIR built on EPA's efforts in the NOx SIP Call to address interstate pollution transport for ozone. CAIR was also EPA's first attempt to address interstate pollution transport for PM2.5, and EPA's stated intention was to provide significant air quality attainment, health, and environmental improvements across the eastern U.S. It required significant reductions in emissions of sulfur dioxide (SO2), which contribute to fine particle concentrations, and emissions of NOx, which contribute to both fine particle and ozone problems. Electric power plants (called electric generating units or EGUs in the rule) were found to be a major source of the SO2 and NOx emissions that contribute to fine particle concentrations and ozone problems downwind.

CAIR's emission reductions requirements were based on controls that EPA had determined to be "highly cost-effective" for EGUs under optional cap and trade programs that covered: (1) annual SO2 emissions, (2) annual NOx emissions, and (3) ozone season

NOx emissions. States retained some theoretical flexibility to choose the measures to adopt to achieve the specified emissions reductions, although EPA expected controls to be applied to EGUs under a model trading rule. EPA required the emissions reductions to be implemented in two phases, with the first phase in 2009 and 2010 (for NOx and SO2, respectively), and the second phase for both pollutants in 2015. The regional SO2 emission caps were set at 3.62 million tons in 2010, dropping to 2.53 million tons in 2015. Annual NOx caps were set at 1.51 million tons in 2009 and 1.26 million tons in 2015, while ozone season NOx caps were 568,000 tons in 2009 and 485,000 tons in 2015. EPA estimated that overall power plant emissions in the covered region would be reduced in 2015 by about 48 percent for SO2, and 54 percent for annual NOx; overall 2015 regional SO2 and NOx emissions were estimated to fall by 32 percent and 14 percent, respectively.

CAIR FIPs

When EPA promulgated the final CAIR, EPA also issued a national finding that states had failed to submit SIPs to address the requirements of section 110(a)(2)(D)(i) with respect to the 1997 ozone and PM2.5 NAAQS. States were to have submitted 110(a)(2)(D)(i) SIPs for those standards by July 2000. This action triggered a 2-year clock for EPA to issue FIPs to address interstate transport. In 2006, EPA promulgated FIPs to ensure that the emissions reductions required by the CAIR were achieved on schedule. The FIPs did not limit states' flexibility in meeting their CAIR requirements as all states remained free to submit SIPs at any time that, if approved by EPA, would replace the FIP for that state.

As the control strategy for the FIPs, EPA adopted the model cap and trade programs that it provided in the CAIR as a control option for states, with minor changes to account for federal, rather than state, implementation.

Judicial Invalidation of CAIR

Petitions for review challenging various aspects of the CAIR were filed in the U.S. Court of Appeals for the D.C. Circuit. In North Carolina v. EPA, 531 F.3d 896, *modified on reh'g* 550 F.3d 1176 (D.C. Cir. 2008), the Court granted several of the petitions for review and remanded the rule to EPA for further proceedings. In its opinion, the Court upheld several challenged aspects of EPA's approach, but also found fatal flaws in the rule that were initially deemed significant enough to warrant vacatur of the CAIR and the associated FIPs in their entirety. In December 2008, however, the Court responded to petitions for rehearing and decided to remand the rule without vacatur to maintain the environmental benefits of the rule while EPA worked to remedy CAIR's flaws as identified in the court's opinion.

One major flaw in CAIR involved the way EPA addressed the issue of "significant contribution" under section 110(a)(2)(D). The court emphasized the importance of individual state contributions to downwind nonattainment areas and held that EPA had failed to adequately measure significant contribution from sources within an individual state to downwind nonattainment areas in other states. Further, the Court noted that EPA had not provided adequate assurance that the trading programs established in CAIR would achieve, or even make measurable progress towards achieving, the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution. For these reasons, it concluded that EPA had not shown that the CAIR rule would achieve measurable progress towards satisfying the statutory mandate of section 110(a)(2)(D)(i)(I) and thus EPA lacked authority for its action. Moreover, it emphasized that because EPA was treating the rule as constituting a complete 110(a)(2)(D)(i)(I) remedy, it must actually require the elimination of emissions that contribute significantly to nonattainment or interfere with maintenance downwind.

The Court further rejected the state budgets for SO2 and NOx that were used to implement the CAIR trading programs, finding the budgets to be insufficiently related to the statutory mandate of eliminating significant contribution and interference with maintenance. It also rejected EPA's use of a reduced allocation of Title IV acid rain allowances to implement compliance with CAIR SO2 requirements, holding that the Act did not give EPA authority to terminate or limit Title IV allowances. In addition, the Court found that EPA had failed to give meaning to the "interfere with maintenance" prong of section 110(a)(2)(D)(i)(I), and that EPA had not demonstrated that the 2015 compliance deadline used in the CAIR was coordinated with the downwind state's deadlines for attaining the NAAQS.

EPA's Proposed 2010 Federal Transport Rule

Introduction

On July 6, 2010, EPA released a proposed rule designed to address the transport of interstate pollution that has long hampered states' efforts to deal with nonattainment and maintenance problems in a comprehensive and effective manner. Specifically, EPA's proposal, called "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone" (the Transport Rule proposal or the proposed TR), would require the reduction of NOx and SO_2 emissions from 32 states in the eastern US to address the contribution of those emissions to nonattainment and maintenance problems associated with the 1997 and 2006 PM2.5 NAAQS and the 1997 ozone NAAQS.

The Transport Rule proposal will, once implemented, completely replace CAIR, which, as mentioned previously, was found unlawful in a variety of respects in 2008 by the US Court of Appeals for the DC Circuit.

Summary of Major Provisions

Major elements of the Transport Rule proposal are summarized below.

Four Separate Emission Control regions—

Annual SO_2—27 states plus DC, split into two groups—
Group 1 (2012 and 2014 caps)—15 states[64]
Group 2 (2012 caps only)—12 states + DC[65]

Annual NOx—27 states + DC[66]
Ozone Season NOx—25 states + DC[67]

Regional Emission Caps

(Annual million tons)

Effective Date	**2012**[68]	**2014**[5]
Annual SO_2	**3.89**	**2.50**[69]
Annual NOx	**1.38**	**1.38**
Ozone Season[70] NOx	**0.64**	**0.64**[71]

General Scope of EPA Analysis

- EPA examined four emission scenarios in developing the Transport Rule proposal—a 2005 base year using estimated actual emissions; a projected 2012 "no CAIR" base case (used to identify nonattainment and maintenance areas affected by upwind pollution); and projected 2014 "no CAIR" base case and control case based on the proposed TR (the 2014 cases were used to estimate costs and benefits produced by the proposal).

- EPA's analysis covered the 37 states east of the Rocky Mountains (i.e., North Dakota and states south and east).

Calculation of State Budget Caps

Like CAIR, the Transport Rule proposal seeks to implement the required emission reductions through the use of state emission budget caps. However, unlike CAIR, caps in the Transport Rule proposal were not determined on a "top-down" regional basis. Rather, they were built from the bottom up based on the amount of emissions in each state found to be significantly contributing to nonattainment or interfering with maintenance in another downwind state, an amount generally equivalent to that portion of a state's contribution that could be eliminated by controls in that state for a specific cost.

In the Transport Proposal, EPA modified the two-step approach used in CAIR for determining a state's significant contribution to downwind nonattainment. Here, EPA adopted a simple formula for the first step, which quantifies and evaluates an individual state's contribution to downwind nonattainment or maintenance. An upwind state will be subject to the transport requirements if the modeled air quality impact in 2012 from its emissions in the most impacted downwind nonattainment or maintenance site is at least 1 percent of the underlying limit value for the relevant NAAQS.[72] One of the advantages of this 1 percent threshold is that it can be applied to any future revised NAAQS.

If a state's downwind contribution exceeded one or more of these 1 percent NAAQS thresholds, EPA proceeded to the second step, a multi-factor analysis that uses maximum control cost thresholds, informed by air quality considerations, to determine the portion of the state's contribution that constitutes the "significant contribution" and "interference with maintenance" required to be eliminated. This process is not nearly as simple as the first step. By way of brief summary, EPA developed EGU emission reduction cost curves for each state and pollutant, showing what level of emission reduction could be achieved at different cost levels in 2012 and 2014; then, looking at both cost and air quality factors, EPA identified "breakpoints" (in terms of cost/ton of pollutant reduced) where attainment and maintenance problems are addressed for all or most areas by control technology that can widely deployed at a reasonable cost. EPA settled on a marginal cost of $2000/ton for SO2 (~cost of new scrubber installations) for Group 1 states, but used a lower value of $300-400/ton SO2 for Group 2 states (~cost of operating existing and planned controls), and $500/ton of NOx (~again, the cost of running existing and planned controls year-round). EPA reasoned that substantial reductions have already been obtained from installations made or planned prior to 2012, and that those installations could be operational by 2012 at the lower cost thresholds, eliminating much of the downwind contribution from states other than the Group 1 states (except for continued PM2.5 problems in some areas in the winter as discussed later). For those Group 1 states, a higher cost threshold (with a longer implementation period—2014) was found to be appropriate in order to obtain the larger SO2 reductions needed to address the larger downwind contribution from those states. For ozone season NOx, EPA determined that $500/ton was a reasonable cost threshold for reductions that could be obtained from EGUs by 2012 for many states. However, EPA's analysis shows that at this cost threshold, 1997 ozone NAAQS problems will continue to persist in Houston, Baton Rouge, and New York City. EPA is conducting further analysis on whether additional reductions above the $500/ton threshold are needed from states linked to those downwind areas.[73]

EPA proposes to control only EGU[74] emissions in this rulemaking, as it found that NOx and SO2 emission reductions below the selected cost thresholds were generally not available from other sectors.

The state emissions budgets were calculated by applying the applicable cost thresholds to state-specific EGU data, before accounting for the "inherent variability in power system operations" (see variability discussion later).

Implementation--Proposed Remedy and Alternatives

EPA proposes to implement the emission reductions necessitated by the emissions budgets for the affected states by issuing FIPs directed at EGUs within each state. States, however, are free to meet their budgets by means of their own SIPs. Such SIPs may require reductions from non-EGU sources.[75]

Responding to the DC Circuit's disapproval of various aspects of CAIR related to the trading of emission allowances, EPA is proposing a remedy that involves the use of new allowances created for this rule, and that places restrictions on interstate trading. Title IV acid rain allowances (used in CAIR) may not be used for compliance with the proposed Transport Rule.[76]

EPA calls its proposed remedy the "state budgets/limited trading" option. This option is designed to meet the NC v. EPA court's requirement that a CAA section 110 (a)(2)(D) remedy must eliminate emissions within each state that are significantly contributing to nonattainment or interference with maintenance in any other state.[77]

Under this approach, EPA will issue 4 discrete types of new emission allowances for 4 separate cap and trade programs corresponding to the 4 different control regimes—Group 1 SO2 allowances, Group 2 SO2 allowances, annual NOx allowances, and ozone season NOx allowances. These allowances will be allocated directly to covered EGUs in a given state in an amount equal to the emission budgets for that state. With the exception of units in Group 1 states in 2014 and thereafter, existing units will receive "allowances commensurate with the unit's emissions reflected in whichever total emissions amount is lower for the state, 2009 emissions or 2012 base case emissions projections." For units in Group 1 states, starting in 2014, allocations would be determined in proportion to the unit's share of the 2014 state budget, as projected by IPM modeling. EPA will reserve 3 percent of the allowances in each state budget as a set aside for new units. Allowance allocations generally would be permanent.

Each source must hold allowances sufficient to cover its emissions, and failure to do so is a violation of the Act.[78] A source may only use an allowance issued for a particular control program for compliance with the emission requirements of that specific regime—for example, Group 1 SO2 allowances can only be used to comply with Group 1 SO2 limits, annual NOx allowances cannot be used to comply with ozone season NOx limits.

In general, the proposed "limited trading" option allows sources to bank allowances, to trade them freely with sources in the same state and trading program, and to trade them with sources in the same program in other states, subject to the following primary limitation. EPA proposes to place limits on the total emissions that may be emitted from EGUs in each state. Those limits will be equal to the state's emission budget, plus a "variability limit," calculated on both an annual and a 3-year rolling average basis. This variability limit, proposed by EPA to account for the annual variability in actual EGU emissions (occasioned, e.g., by a nuclear plant outage), will be equal to 10% of a state's budget or 5000 tons for annual NOx, 1700 tons for SO2, and 2100 tons for ozone season NOx, whichever is greater.[79] Starting in 2014, EPA proposes to restrict interstate trading by means of "assurance" provisions designed to assure that a state does not exceed the sum of its budget plus its variability limit.[80] These assurance provisions require an EGU operating in a state where total covered emissions exceed the sum of the state budget plus the variability limit to surrender an allowance to cover each ton of the EGU's emissions that exceed its share of the state's emission budget plus variability limit.[81] EPA asserts that this approach is consistent with the DC Circuit's decision in NC v. EPA, as it believes that this allowance surrender requirement will be adequate to deter sources from exceeding a state's overall emission limit.

EPA also describes two alternate implementation approaches, and requests comments on each. The first alternate remedy—called the "state budgets/intrastate trading" option—is similar to the proposed remedy, with the significant exception that all interstate allowance trading is prohibited—only trading with other EGUs within the same state is allowed.[82] Under this option, there would be no variability limits and no assurance provisions. Allowance banking would be permitted. In order to address the potential for dominant power companies within a single state from controlling allowance prices in the state's allowance market, EPA proposes to reserve a small number of allowances from the allocations of large covered sources and auction them off directly to small covered sources.

The second alternate remedy is called the "direct control" option, where EPA would assign input-based emission rate limits to individual sources. A company would be allowed to average emissions at its own units within each state to meet the specified in-state rate limits, but there would be no allowances and no trading. To address the potential variability associated with emission rate limits, each state's total EGU emissions would also be capped at a level equal to the sum of the state's emission budget plus its variability limit. EGU emission rates would be set at levels such that, if the units operated at the levels assumed in the state budgets, total emissions from these units would sum to the state budgets. This option would include state variability limits and assurance provisions similar to the proposed option, except that the assurance provisions would commence in 2012 rather than 2014.

Projected Emissions Reductions—

EPA projected overall emission reductions from the Transport Proposal within the control region, assuming in its base case that CAIR requirements are not applicable (since they will disappear with implementation of the new Transport Proposal), as follows—

SO2 reductions from the proposed TR, stated in various ways—
- 60 percent EGU control region reduction from base case (no TR or CAIR) 2012;
- 64 percent EGU control region reduction from base case (no TR or CAIR) 2014;
- 62% EGU control region reduction from 2005 actual emissions in 2012;
- 71% EGU control region reduction from 2005 actual emissions by 2014

Annual NOx reductions from the proposed TR, stated in various ways—
- 35 percent EGU control region reduction from base case (no TR or CAIR) 2012; same in 2014
- 52 percent EGU control region reduction from 2005 actual emissions in 2012; same in 2014

Ozone season NOx reductions from the proposed TR, stated in various ways—
- 14 percent EGU control region reduction from base case (no TR or CAIR) 2012; same in 2014
- 33 percent EGU control region reduction from 2005 actual emissions in 2012; same in 2014

EPA has also projected national EGU emissions for several scenarios in its IPM runs, and CATF has estimated emission reductions as the difference between several base and control cases below:[83]

Projected National EGU Emissions— Base Case, Control Case, and Reductions— 2012 and 2015 (annual million tons)

	2012 Base Case	2012 Transport Proposal	2012 EGU Reductions	2015 Base Case	2015 Transport Proposal	2015 EGU Reductions	2020 Base Case	2020 Transport Proposal	2020 EGU Reductions
Annual SO_2	9.5	4.8	4.7	8.5	4.1	4.4	8.4	4.1	4.3
Annual NOx	3.0	2.2	0.8	3.0	2.2	0.8	3.1	2.3	0.8

Projected Air Quality and Attainment Impacts—

EPA projected that the average reductions in PM and ozone concentrations in 2014 for monitoring sites in the eastern US that are projected to be in nonattainment in the 2014 base case will be—
Annual PM2.5—2.4 *u*g.m3;
24 hour PM2.5—4.3 *u*g/m3;
8 hour ozone—0.3 ppb.

EPA projected the following attainment benefits from the proposed rule as described in the table below:

Nonattainment Projections for the Transport Proposal

	Projected Nonattainment Counties in East	
Annual PM2.5	**2012**	**2014**
Base Case	**32**	**15**
After TR 2014	**--**	**1**
Daily PM2.5	**2012**	**2014**
Base Case	**92**	**54**
After TR 2014	**--**	**17**
Ozone	**2012**	**2014**
Base Case	**11**	**7**
After TR 2014	**--**	**7**

Projected Costs and Benefits—

EPA in its proposed Regulatory Impact Analysis (RIA) of the proposal estimates the projected costs and benefits of the proposed Transport Rule. EPA estimates that the premature deaths avoided in 2014 at 14,000 using the Pope premature mortality study and 36,000 using the Laden study. In terms of monetized benefits in 2014, EPA using its National Academy of Science endorsed benefits methodology finds benefits range from of $110-120 billion in 2014, using Pope premature mortality study ($100-110B of total) to $270-290 billion, using the Laden study. The benefits compared to costs (see below) ratio (i.e., benefits divided by costs) range from 50:1 to 147:1; with annual net benefits (benefits less costs) of $120 to 264 billion, leaving significant "headroom" for further benefit-cost justified strengthening of the rule. EPA identifies other numerous public health and environmental benefits, most of which were not monetized. EPA projected carbon dioxide emissions reduced by the rule in 2014 due to modest retirements and re-dispatch to be 15 MT.

Energy and cost impacts

In addition, EPA's economic analysis of the proposed Transport Rule demonstrates that it will cause no noticeable increase in electricity or gas prices, no appreciable decrease in coal use or generation, and no shifts in coal production between coal producing regions. Specifically, EPA finds that the cost to power sector of complying with the rule will be $3.7B(illion) in 2012 and $2.8B in 2014 (2006$) with social costs in 2014--$2.0B (3 percent discount rate); $2.2B (7 percent discount rate). EPA projects a retail electricity price increase less than 2.5 percent in 2012, and 1.5 percent in 2014 with a projected delivered coal price increase less than 7 percent in 2012, and 4 percent in 2014. EPA projects a decrease in coal use by power sector of only 0.3 percent in 2012, and 0.8 percent in 2014. The projected delivered natural gas price increases less than 1.7 percent in 2012, and 0.5 percent in 2014.

Other Anticipated Power Sector Rulemakings

EPA is considering requiring additional emission reductions in the following areas when it finalizes the Transport Rule. First, EPA states its intention in the proposal to analyze potential upwind contribution to residual 24-hour PM2.5 NAAQS exceedance problems that are concentrated in the winter months. This may result in additional annual NOx and SOx reduction requirements.

Second, EPA notes that its analysis shows that SO2 emissions are expected to increase in states not regulated under the proposed Transport Rule proposal as a result of sources in those states opting to use higher sulfur coals. These projected emission increases vary from state to state. The largest projected increases are in Texas, and EPA projects that emissions increases in Texas will be large enough to exceed the 0.15 *u*g/m3 significant contribution threshold for the annual PM NAAQS; thus, EPA is considering whether Texas should be included in the states subject to the annual SO2 limits.

Finally, EPA is also conducting additional analysis to determine whether additional reductions of ozone season NOx are needed in the final rule to help abate persistent ozone problems in Houston, Baton Rouge and New York City.

Turning to other potential rulemakings, EPA states its intention to propose additional transport proposals as necessary to address upwind transport in connection with future revisions to the ozone or fine PM NAAQS, and specifically states its intention to promulgate a revised ozone NAAQS later this year, and to propose next year a rulemaking addressing any associated needed reduction in transported NOx, with a final rule expected in 2012.

In addition, EPA also notes other future rulemakings that will impact the power sector:

- CAA section 112(d) "MACT" standards, to be proposed by March 2011;
- Revisions to the NSPS for coal and oil-fired EGUs (currently scheduled for proposal at the same time);
- Best available retrofit technology (BART) and regional haze programs to protect visibility.

EPA adds that it will likely "be compelled to respond to a pending petition to set standards for the emissions of greenhouse gases from EGUs under the NSPS program," and further, that under the Johnson memo, "beginning in 2011 new and modified sources of greenhouse gas (GHG) emissions, including EGUs, will be subject to permits un der the PSD program requiring them to adopt BACT for their EGUs."

Aspects of the Transport Proposal that Need Strengthening

Introduction

While CATF believes that the proposed Transport Rule is a good step towards requiring needed air pollution reductions in the US electric power sector, EPA's proposal falls short of producing the amount of cost-effective reductions that are reasonably obtainable and necessary to protect human health and the environment..

Several key points must be kept in mind when evaluating the appropriate level of emission reductions from the power sector. First, the public health and environmental benefits of reductions of NOx and SO2 emissions from power plants are vastly greater than the cost of obtaining those reductions—monetizable benefits literally are several orders of magnitude greater than cost (and many benefits are not monetizable). The Transport Rule proposal achieves estimated benefits of roughly 50 to 150 times greater than costs. In other words, costs would need to increase by at least 50 times before they even approached the level of public health benefits provided (and of course, additional reductions would produce additional benefits). Furthermore, EPA's analysis shows that reductions from the power sector are more cost-effective than reductions available from most other sources; this is especially true for SO2, where power plants are by far the dominant source. EPA's proposal will save thousands of lives. A tighter regulation could save many more.

Second, the technology to control SOx emissions (flue gas desulfurization or "scrubbers") and NOx emissions (low NOx burners and selective catalytic reduction or "SCR") are well established, effective, reliable and widely available today. At this late hour in the stuggle to reduce transported air pollution, there is simply no good reason not to tightly regulate air emissions from power plants so that each plant employs these controls.

Third, power plants can and have installed these pollution controls without producing significant adverse impacts. The proof is in the pudding—since 2004, power plants in the eastern U.S. have installed over 120 scrubbers, reducing national annual SO2 emissions from 11 million tons in 2004 to less than 6 million tons in 2009. The power sector has accomplished this without impacting electric system reliability or causing economic dislocation. However, more can and must be done—as of 2009, almost 2/3 of US coal-fired units (i.e., over 700) still did not have SO2 scrubbers.

CATF welcomes EPA's stated intention to promulgate a number of rules in the future to require emission reductions from this sector beyond those in the Transport Rule proposal (see earlier discussion). However, often good intentions are not completely realized. Furthermore, the Transport Rule itself should require deeper reductions than proposed. In fact, the Transport Proposal is essentially designed simply to maintain the emission reductions from controls that are already in place or planned to be in place—in effect, the Transport Proposal's 2012 limits are simply nailing down (and in some cases, accelerating) the reductions driven by CAIR. The only additional reductions required by the Transport Proposal are SO2 reductions in 2014 from EGUs in the 15 Group 1 states, and EPA expects that only about 14 GW of scrubber capacity retrofits and less than 1GW of SCR capacity retrofits will need to be installed to comply with these 2014 requirements.[84]

Additional Reductions are Required Under the Proposed Framework for the Rule

According to EPA's own statements and using its own approach to addressing transported air pollution under section 110(a)(2)(D), the Transport Rule proposal does not eliminate all of the projected contribution in upwind states to downwind nonattainment and maintenance problems. EPA's atmospheric modeling shows that even after the TR is implemented:

- several downwind areas (Birmingham, Alabama and Allegheny County, Pennsylvania) will still experience nonattainment or maintenance problems under the 1997 annual PM2.5 NAQQS;
- at least 14 downwind areas will continue experience problems with nonattainment or maintenance of the 24-hour PM2.5 NAAQS, at least in the winter;

- several downwind areas (Houston, Baton Rouge and New York City) will also continue to experience with the ozone NAAQS attainment and maintenance problems; and
- sources in several states that are outside of the proposed control region of the TR will increase emissions following implementation of the rule, as they will be subject only to the much weaker Title IV acid rain restrictions; in fact, the increase in one state (Texas) is large enough to cause it to become a significant contributor to downwind nonattainment and maintenance problems.

These residual nonattainment and maintenance problems can easily be addressed by EPA by requiring deeper reductions while keeping within the framework of the proposal. With respect to PM2.5, Group 2 states have minimal obligations under the current proposal, but there are clearly substantial additional reductions that can be obtained from those states at the $2000/ton cost threshold applicable under the proposal to Group 1 states; thus, all states should be required to meet the Group 1 state requirements. In addition, there are also substantial additional SO2 reductions available at slightly higher costs than $2000/ton; according to EPA estimates, additional reductions of about 500,000 tons of SO2 could be obtained in 2014 by increasing the proposal's SO2 cost threshold to $2400/ton. With respect to ozone, EPA should raise the $500/ton minimum cost threshold in the Transport Rule proposal for requiring ozone season NOx reductions, keeping in mind that EPA found in the 1998 NOx SIP Call that a cost threshold of up to $2500/ton of NOx removed was highly cost-effective. Furthermore, EPA should include an anti-backsliding provision to prevent non-regulated states from increasing transported emissions.

Other Approaches for Procuring Additional Needed Emission Reductions

CATF believes that EPA should consider other approaches to its Transport Rule proposal to secure additional cost-effective emission reductions from the power sector. First, EPA should consider lowering the 1 percent NAAQS contribution threshold. Any measureable contribution to reduced ambient air quality in a downwind state with nonattainment or maintenance problems is significant, and EPA should include all such states with measurable contributions in its control program. Secondly, EPA should raise the artificially low cost thresholds that effectively increase the level of the emission caps and allow thousands of tons of unnecessary and deadly emissions each year. Third, EPA should require other industrial sectors to control their SO2 and NOx emissions. Over a decade ago, EPA's 1998 NOx SIP Call targeted non-EGU stationary sources such as large industrial boilers and turbines and cement plants for NOx emission reductions. EPA should investigate control costs from large industrial sources, and if they are within the range of similar levels of EGU control costs, require the appropriate emission reductions.

Recommended Power Sector Emission Levels

In 2004, CATF submitted several sets of comments on EPA proposed rulemakings that resulted in the final CAIR. In those comments, CATF urged EPA to tighten its proposed

CAIR emission caps substantially, and demonstrated that tighter caps would be cost-effective, would not cause unreasonable energy price spikes, would save substantially more lives and would produce substantially greater benefits to society than EPA's proposed CAIR. Specifically, CATF recommended that EPA reduce the proposed regional emission caps as follows:

- a CAIR region SO_2 cap of 1.84 million tons in 2010, and
- a two phase NOx cap, 1.6 million tons in 2010 and 1.04 million tons in 2012.

Using the same methodology that EPA used to estimate costs and benefits of its

regulatory proposals, CATF estimated the comparative costs and benefits of its preferred alternative to EPA's CAIR proposal as follows:

	EPA CAIR Proposal—2010	**CATF Alternate Control Scenario—2010**	**EPA CAIR Proposal—2015**	**CATF Alternate Control Scenario—2015**
Costs ($Billion)	3.4	9.1	4.1	8.9
Benefits ($Billion)	53	99	77	129
Net Benefits ($Billion)	**50**	**90**	73	**120**
Lives Saved	**9600**	**18000**	**13000**	**22000**

Although these comparisons were produced over 5 years ago, CATF believes that they demonstrate that the Transport Proposal, which is similar to CAIR in its ultimate effect, can be substantially tightened while saving more lives and increasing the net benefits of the rule. CATF also believes that our recommended power sector emission limits recommended in 2004 are still achievable and beneficial today, and should be implemented by EPA.

S. 2995, the Clean Air Act Amendments of 2010

In addition to supporting EPA strengthening and finalizing the Transport Rule, CATF supports passage of S. 2995, the Clean Air Act Amendments of 2010 (CAAA of 2010). Although time in the current session of Congress is short, CATF has long favored a comprehensive legislative solution to the problem of power plant pollution covering SO2, NOx, and power plant HAPs. In producing the proposed Transport Rule to replace the

CAIR rule, EPA has done an admirable job in navigating the legal minefield laid for it by the D.C. Circuit. But, we know that just as the Bush CAIR and CAMR rules were challenged and struck down, so a new set of power plant regulations may founder on the shoals of court challenges and delays. To guarantee the certainty of environmental improvement that the public health and the environment demand and the regulatory certainty that the electric power industry craves, Congress should act now to pass the steep reductions in these three power plant pollutants as proposed by the CAAA of 2010. While stringent, comprehensive legislative action on power plant pollution would be ideal, CATF recognizes that the time window for legislative action in the current session of Congress is rapidly closing and; therefore, CATF fully supports EPA's efforts to move forward with a strengthened Transport Rule and the other power plant rules that EPA is committed and legally obliged to issue.

Introduced on February 4, 2010, the proposed Clean Air Act Amendments of 2010 would codify stringent, national caps for sulfur dioxide and nitrogen oxides while providing a crucial "backstop" for EPA's regulatory process of setting maximum available control technology ("MACT") standards for power plant air toxics. The bill, which is also known as the Carper-Alexander "3P" bill (for the three categories of pollutants that it covers) enjoys broad, bi-partisan support as it is co-sponsored by Senators Carper, Alexander, Klobuchar, Collins, Gregg, Kaufman, Graham, Feinstein, Shaheen, Schumer, Lieberman, Snowe, Gillibrand, Dodd, and Cardin. The bill codifies the Clean Air Interstate Rule (CAIR) for 2010 and 2011 and then builds upon the successful Acid Rain program (CAA Title IV) setting for national sulfur dioxide emissions a 3.5 million ton per year cap beginning in 2012 that drops to 2 million tons in 2015 and to 1.5 million tons in 2018. Beginning in 2021, EPA may tighten the annual emissions cap if necessary to meet a number of enumerated air quality objectives. This provision alone warrants support for the bill as it represents the tightest national sulfur dioxide cap ever contained in proposed legislation, will result in tens of thousands of avoided deaths due to power plant-related particulate matter exposure, and is fully reflective of feasible, achievable reductions available through broad deployment of flue gas desulfurization (FGD or "scrubbers") nationwide.

In addition, for nitrogen oxides, the bill would create two regional trading zones, for the East and the West. Beginning in 2012, the eastern NOx cap would be 1.39 million tons per year with a cap of 520,000 tons in the west. Beginning in 2015, the eastern cap would be 1.3 million tons per year with a western cap of 320,000 tons. Beginning in 2020, EPA may tighten the annual emissions cap if necessary to achieve certain enumerated air quality objectives. With respect to power plant toxics (i.e., hazardous air pollutants or "HAPs"), if the court-ordered EPA rulemaking concerning utility MACT is delayed, the bill directs EPA to cut mercury emissions from coal plants by at least 90 percent by 2015.

A comparison between the emissions benefits of the proposed CAAA 2010 and EPA's proposed Transport Rule is instructive. CATF performed this analysis based on data contained in EPA's Transport Rule proposal as posted on its website and the EPA analysis of the bill requested by Senators Carper and Vitter by letter dated April 15, 2010 and provided by EPA on July 16, 2010.[85] A direct comparison between the proposed Clean Air Act Amendments of 2010 and the Transport Rule demonstrates that the bill would achieve far greater reductions, particularly of sulfur dioxide emissions, and thus deliver greater air quality improvements and health-related benefits. The following table[86] compares the national emissions and health benefits of the two proposed policies:

Annual Sulfur Dioxide Emissions, Lives Saved, and Monetized Benefits under Transport Rule vs. CAAA of 2010

	2012	2015	2020	2025	Through 2025
No-CAIR emissions	9.5	8.5	8.4	8.4	121.4
TR emissions	4.8	4.1	4.1	4.0	59.4
CAAA 2010 emissions	3.9	3.4	2.9	2.1	45.3
TR emissions reduced	4.7	4.4	4.3	4.4	62.0
CAAA 2010 emissions reduced	5.6	5.1	5.5	6.3	76.1
TR lives saved	14,883	14,000	13,616	13,933	196,662
CAAA 2010 lives saved	17,773	16,150	17,416	19,950	241,099
CAAA 2010 lives saved over TR	2,890	2150	3,800	6,000	44,420
Valuation of CAAA 2010 over TR	$20 billion	$15 Billion	$27 billion	$42 billion	$312 billion

The comparison makes clear that the proposed CAAA 2010 saves over 44,000 more lives through 2025. This is true for two reasons: first, the CAAA 2010 sulfur dioxide cap is tighter in the Transport Rule region; and, second, the CAAA 2010 is national in geographic scope, meaning that it requires reductions in states that the Transport Rule does not include.

The following table summarizes the costs and other economic impacts from the proposed Transport Rule and the CAAA of 2010:

Costs, Electricity Prices, Natural Gas Prices, and Coal Generation under the Transport Rule and the CAAA of 2010 vs. No-CAIR Base Case

	Transport Rule				CAAA of 2010				TR vs. CAAA of 2010			
	2012	2015	2020	2025	2012	2015	2020	2025	2012	2015	2020	2025
Costs (B$2006)	3.7	2.7	2	2.1	-6	-3.3	3.3	5.8	-9.7	-6.1	1.2	3.8
Electricity Price Mills/kWh	3.4	.98	.94	.54	-8.7	-3.1	5.5	12.4	-12.1	-4.1	4.6	12
Natural Gas Price $/MMBtu	.11	.03	.01	.01	-.86	-0.1	.89	.81	-.97	-.13	.91	0.8
Coal Generation 1000 GWh	-9	-18	-15	-11	-67	-250	-403	-414	-57	-232	-388	-403

The cost of this bill is not too much to pay to save tens of thousands of lives per year, clear the vistas in our national parks, help restore the health of our forests and lakes, cut summer ozone smog, and virtually eliminate the power sector's contribution to mercury contamination in our fish. CATF submits that this represents a small price to pay and many years overdue.

The eastern nitrogen oxide emissions caps under the CAAA of 2010 and the Transport Rule are very similar, while the CAAA of 2010 would result in nitrogen oxide reductions in the west that are not achieved under the Transport Rule. In its analysis, EPA estimated the benefits of adopting a tighter nitrogen oxides cap in the east (.9 million tons per year v. 1.3 million tons per year). EPA's analysis suggests that the annual benefits of the tighter cap ($10 billion in 2025) outweigh the annual costs ($1.5 billion in 2025) while producing significant air quality improvements. This analysis should apply with equal force to the Transport Rule, which contains the identical eastern nitrogen oxide cap for a very comparable set of states. Accordingly, the sponsors of the proposed CAAA of 2010 should consider tightening the eastern nitrogen oxides cap during any mark-up of the bill and, similarly, EPA should tighten the nitrogen oxides caps when it finalizes the Transport Rule as EPA's own analysis demonstrates the significant benefits of doing so. EPA's analysis of the proposed CAAA of 2010 also demonstrates that passage of the bill would result in no noticeable increase in electricity or natural gas prices, no appreciable decrease in coal generation or use, or shifts in coal production or use within coal-producing regions.

[1] Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (2007).
[2] *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), *cert denied sub nom. Util. Air Regulatory Group v. New Jersey*, 2009 U.S. LEXIS 1329 (U.S. Feb. 23, 2009).
[3] *See e.g., NRDC v. EPA*, 489 F.3d 1364, *reh'g & reh'g en banc denied,* 2007 U.S. App. LEXIS 22229 (D.C. Cir. 2007)(reaffirming the holding in *National Lime,* 233 F.3d 625 (D.C. Cir. 2000) that all HAPs emitted by a listed source category must be regulated).
[4] North Carolina v. EPA, 531 F.3d 896 (D.C. Cir. 2008). See also, Center for Energy and Economic Development v. EPA, 398 F.3d 653 (D.C. Cir. 2005)(striking down the "Regional Haze" rule.)
[5] Available online at: http://www.epa.gov/climatechange/emissions/co2_human.html
[6] Comments of Clean Air Task Force *et al.* submitted on "Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" 74 Fed. Reg. 18,886 (Apr. 24, 2009), Docket ID No. EPA-HQ-OAR-2009-0171 (June 23, 2009) available online at: www.regulations.gov
[7] http://www.catf.us/resources/testimony/files/20090709-Carper_CAPA_CS_EPW.pdf
[8] See e.g., Pope. C.A., Burnett, R.T., Thun, M.J, Calle, E.E., Krewski, D., Ito, Kaz, Thurston, G.D., (2002). Lung cancer, cardiopulmonary mortality, and long term exposure to fine particulate air pollution. Journal of the American Medical Association, vol. 287, p. 1132-1141; Peters, A., Pope, A.C. (2002). Cardiopulmonary mortality and air pollution. The Lancet v. 360, p. 1184 October 19, 2002. Gold, D. et al., "Ambient Pollution and Heart Rate Variability," Circulation, v. 101, 1267-1273, American Heart Association (March 21, 200); Peters, A. et al., "Increases in Heart Rate Variability During an Air Pollution Episode," 150 American Journal of Epidemiology, p. 1094-1098 (1999); Peters, A. et al., "Air Pollution and Incidence of Cardiac Arrhythmia," 11 Epidemiology, no. 1, p. 11-17 (2000); Schwartz, J., "Air Pollution and Hospital Admissions for Heart Disease in Eight U.S. Counties, 10 Epidemiology 17-22 (1999).
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[14] http://www.epa.gov/airmarkt/progress/docs/2007ARPReport.pdf at 6 and 29.
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[60] While the test for "significant contribution" is a legal and technical one, the remedy for a section 126 petition is based on equitable principles, meaning that a petitioning state must demonstrate that it has "clean hands" i.e., that it requires the same level of emissions control from its in-state sources as it seeks to impose on its upwind neighbors. See discussion of "State Power Plant Regulation and Legislation" and "NSR Enforcement" infra.

[61] In 2005, North Carolina initiated a section 126 petition against 13 upwind states in the southeast. EPA denied that petition saying that CAIR provided the necessary remedy. The D.C. Circuit in striking down the CAIR rule undermined the justification for EPA's denial of North Carolina's section 126 petition, however, no further action has been taken.

[62] See: http://www.epa.gov/oecaerth/resources/cases/civil/caa/coal/index.html

[63] AL, AZ, CA, CO, CT, DE, GA, IL, LA, ME, MD, MA, MN, MO, MT, NH, NJ, NY, NC, OR, TX, WA, and WI.

[64] The Group 1 SO_2 region consists of: GA, IL, IN, IA, KY, MI, MO, NY, NC, OH, PA, TN, VA, WV and WI.

[65] The Group 2 SO_2 region consists of: DC, AL, CT, DE, FL, KN, LA, MD, MA, MN, NE, NJ and SC.

[66] The annual NOx (and annual SO2) region consists of the combined Group 1 and 2 SO2 regions.

[67] The ozone season NOx region consists of: DC, AL, AR, CT, DE, FL, GA, IL, IN, KN, KY, LA, MD, MI, MS, NJ, NY, NC, OH, OK, PA, SC, TN, TX, VA and WV.

[68] The annual NOx and SO2 limits will be effective January 1, while the seasonal NOx limits will be effective May 1.

[69] The cap was calculated on basis of entire 27 state + DC region, but only Group 1 states must make additional reductions.

[70] For purposes of the cap, the ozone season is the 5 month period from May through September.

[71] EPA states its intention in the Transport Proposal preamble to propose a new transport rule in 2011 (final 2012) to require reductions needed to address significant contribution to nonattainment/maintenance of a revised ozone NAAQS anticipated later in 2010.

[72] Thus, the significant contribution threshold is 0.15 *ug*/m3 for the annual PM2.5 NAAQS, 0.35*ug*/m3 for the 24-hour PM NAAQS, and 0.8 ppb for the 8-hour ozone NAAQS.

[73] States found by EPA to be linked to Houston and Baton Rouge are AL, AR, FL, GA, IL, KY, LA, MS, TN and TX. States linked to NYC are CT, DE, IN, KY, MD, NJ, NC, OH, PA, VA and WV.

[74] An EGU subject to the Transport Proposal is a fossil fuel-fired combustion device serving a generator with a nameplate capacity of more than 25 MWe producing electricity for sale. Certain cogenerators and solid waste incinerators are exempt from the FIP requirements. EPA proposes to allow non-covered units to opt in to one or more of the trading programs.

[75] EPA does not expect that to happen, as it believes that EGU reductions are the most cost-effective, and its modeling is based on EGU reductions.

[76] EPA is investigating the use of existing NOx allowances, but has not authorized their use as yet.

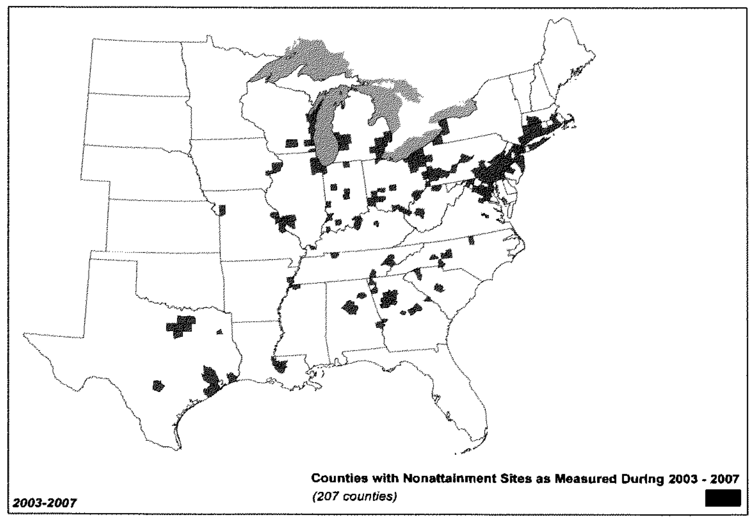
[77] To do this, EPA must measure the level of emissions in each upwind state that are significantly contributing to nonattainment or interfering with maintenance in each other linked downwind state, and eliminate those emissions from sources *within the upwind state.*
[78] One allowance covers one ton of emissions.
[79] The variability of a 3-year rolling average is equal to the annual variability divided by the square root of three.
[80] The assurance provisions will not apply until 2014, so allowance trading is not affected by these provisions in 2012 or 2013.
[81] In effect, this means that a source wishing to acquire out of state emission allowances above its pro rata share of an "exceeding state's" emission budget plus variability limit would need to acquire 2 allowances for every ton of excess emissions—one to surrender under the "assurance provisions," and one to hold to cover its emissions under the general compliance provisions.
[82] Under this option a source could only use for emissions compliance purposes an allowance issued by the state in which it was located. Thus, this option provides a "hard" cap equal to the state budget.
[83] Again, the base cases assume no CAIR and no Transport Rule.
[84] This compares with the actual installation of about 20GW of scrubber capacity by the power sector in each of 2008 and 2009.
[85] See: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html; U.S. EPA, Office of Air and Radiation, "EPA Analysis of Alternative SO2 and NOx Caps for Senator Carper" (July 16, 2010); and http://www.epa.gov/airmarkets/progsregs/cair/multi.html
[86] Although, frustratingly, EPA's analysis of the CAAA of 2010 compared the emissions levels and benefits of the bill to an illogical base case i.e., one assuming the judicially-invalidated CAIR rule is in place, EPA has posted the results of its national Integrated Planning Model (IPM) runs for the No-CAIR base case, the proposed Transport Rule, and the CAAA of 2010 on its website as well as the estimated benefits of the proposed rule in avoided premature deaths. In addition, EPA reported its projected national sulfur dioxide emissions under the CAAA 2010 as part of its analysis affording the ability to compare the two emissions and health benefits of the particulate matter reductions under the two policies.

Clean Air Subcommittee Hearing Oversight: EPA's Proposed Transport Rule

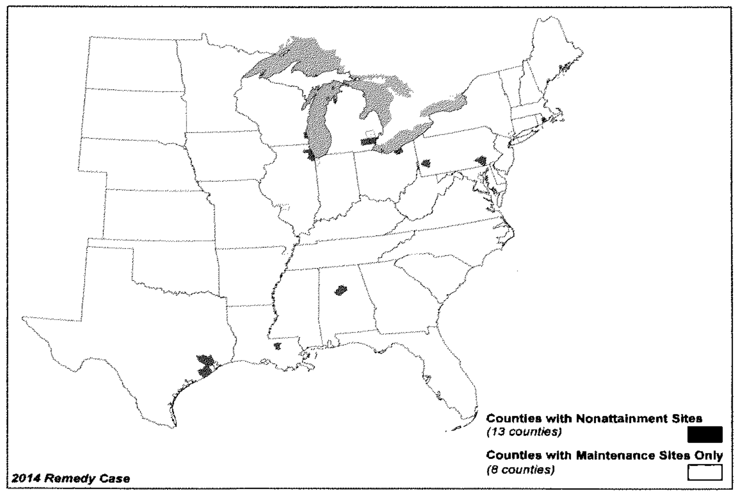
Slides Accompanying Testimony of the Clean Air Task Force

July 22, 2010

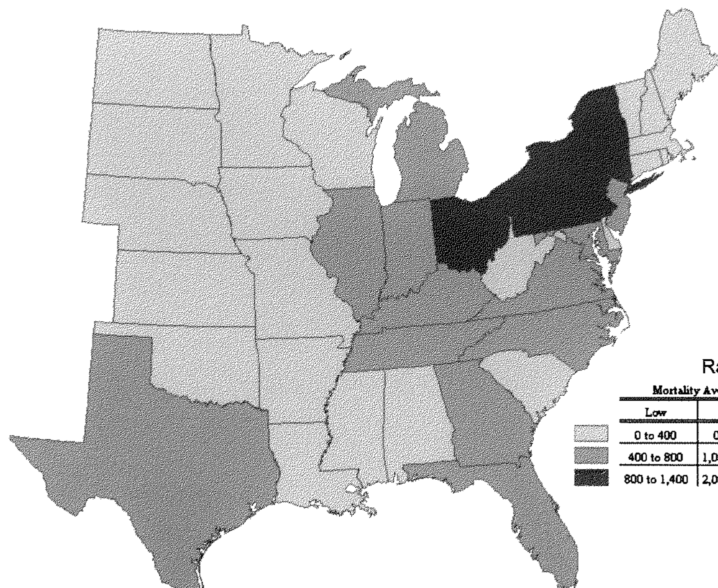
Map A: Counties Violating Air Quality Standards in the Proposed Transport Rule Region (based on 2003-07 air quality monitoring data)



Map B: Counties with Monitors Projected to Have Ozone and PM2.5 Air Quality Problems in 2014 With the Proposed Transport Rule



Billions of Dollars of Health Benefits in 2014



Ranges of Benefits

	Mortality Avoided		Monetized Benefits (billion $)	
	Low	High	Low	High
	0 to 400	0 to 1,000	0 to 4	0 to 10
	400 to 800	1,000 to 2,000	4 to 7	10 to 15
	800 to 1,400	2,000 to 3,600	7 to 12	15 to 29

Maine, New Hampshire, Vermont, Rhode Island, North and South Dakota receive benefits and are not in the Transport Rule region. Transport Rule RIA, Table A-4 and A-5; mortality impacts estimated using Laden et al. (2006), Levy et al. (2005), Pope et al. (2002) and Bell et al. (2004); monetized benefits discounted at 3% 4 4

Annual Sulfur Dioxide Emissions, Lives Saved, and Monetized Benefits under Transport Rule vs. CAAA of 2010

	2012	2015	2020	2025	Through 2025
No-CAIR emissions	9.5	8.5	8.4	8.4	121.4
TR emissions	4.8	4.1	4.1	4.0	59.4
CAAA 2010 emissions	3.9	3.4	2.9	2.1	45.3
TR emissions reduced	4.7	4.4	4.3	4.4	62.0
CAAA 2010 emissions reduced	5.6	5.1	5.5	6.3	76.1
TR lives saved	14,883	14,000	13,616	13,933	196,662
CAAA 2010 lives saved	17,773	16,150	17,416	19,950	241,099
CAAA 2010 lives saved over TR	2,890	2150	3,800	6,000	44,420
Valuation of CAAA 2010 over TR	$20 billion	$15 Billion	$27 billion	$42 billion	$312 billion

Costs, Electricity Prices, Natural Gas Prices, and Coal Generation under the Transport Rule and the CAAA of 2010 vs. No-CAIR Base Case

	Transport Rule				CAAA of 2010				TR vs. CAAA of 2010			
	2012	2015	2020	2025	2012	2015	2020	2025	2012	2015	2020	2025
Costs (B$2006)	3.7	2.7	2	2.1	-6	-3.3	3.3	5.8	-9.7	-6.1	1.2	3.8
Electricity Price Mills/kWh	3.4	.98	.94	.54	-8.7	-3.1	5.5	12.4	-12.1	-4.1	4.6	12
Natural Gas Price $/MMBtu	.11	.03	.01	.01	-.86	-0.1	.89	.81	-.97	-.13	.91	0.8
Coal Generation 1000 GWh	-9	-18	-15	-11	-67	-250	-403	-414	-57	-232	-388	-403

"You mean to spew more sulfur, nitrogen and mercury, and less carbon?" he said of such a deal. "That's not my idea of progress."

--Sen. Lamar Alexander

Senator CARPER. Senator Alexander will be pleased to know that even though he wasn't here, he was quoted. I think we have had excellent testimony from each of you, and we are grateful for that, for your contributions to the debate and hopefully the resolution of these issues in the months to come.

I am just going to ask one question, and then I am going to head out the door and turn the gavel over to Senator Voinovich.

A question, if I could, for Eric Svenson. In Mr. Korleski's statement, he indicated he is concerned about any tightening of the sulfur dioxide budget in the future might simply be technically really infeasible. The Clean Air Act Amendments of 2010 that Senator Alexander and I and others have offered has much stronger sulfur dioxide marks than the Transport Rule.

We have heard from utilities that tighter targets are feasible, although some would disagree on the timeline, as you know. But most agree that the reductions are feasible.

Let me just ask, is PSEG on track to meet the levels and timetables in the Transport Rule, and second, do you believe that we can easily meet tighter targets in SO_x and NO_x than in the Transport Rule?

Mr. SVENSON. Relative to the question—thank you, Mr. Chairman, for the question—one is, PSEG is definitely on track to meet the targets. As a matter of fact where we are today in our requirements, the status of our coal burning plants and other plants, I believe we are really 4 years ahead of schedule relative to what the Transport Rule is going to require by 2014.

I actually also believe that PSEG's fleet is actually well positioned for even the mercury MACT rule and as well as for meeting future maximum achievable control technology requirements for hazardous air pollutants. I believe there are a lot of things—at least what I can see there—that are doable.

But having said that, always these things are case-specific and so on. So as far as, health-based standards are going to be continually evolving. What I liked about the Transport Rule is it is constantly reflecting that it is going to take that updated information and there will be new requirements. I would like to point out that in the industry—back between 1999 and 2008, the industry installed over 270 gigawatts—270 gigawatts— of natural gas-fired generation. In a period of 2001 to 2003, installed 163 gigawatts of that generation, of new natural gas-fired generation.

So my answer to you about can the industry adapt to these new, more stringent requirements, it may not all come down to simply adding back in controls onto a coal plant. It may necessitate, under these caps, eventually phasing out a plant and repowering it with a new natural gas combined cycle plant or something of that sort. I believe that that is doable.

Senator CARPER. Thanks very much. I apologize to our witnesses and my colleagues for slipping out on you. We all know we have problems, certainly challenges on the environmental front, on the health front. We also have challenges with respect to budget deficits. We are looking at a budget deficit; we basically doubled our Nation's debt from 2001 to 2008. We are on track, if we are not careful, to double it again over the next decade.

One of the issues that we have worked on, Senators Coburn, McCaskill, Collins, and I, on this legislation, in a day and age where last year, almost $100 billion of improper payments, mostly overpayments, made by Federal agencies, not including Department of Defense, not including part of Medicare, $98 billion worth of improper payments. We are saying with this legislation that the President is going to sign in about 30 minutes that agencies, all Federal agencies have to report their improper payments. They have to stop making their improper payments. And they have to go out and recover money that has been improperly paid, overpaid in some cases, fraudulently paid.

So that is what we are about to do. And if we can do, after 6 weeks of effort, achieve a bipartisan consensus, bicameral legislation, that the President is going to sign, maybe, George, maybe, my friend, maybe we can hammer something out here before you are ready to ride off into the sunrise.

So with that said, the hearing is yours. I look forward to talking with you this afternoon. Thank you. Thank you all.

Senator VOINOVICH [presiding]. One of the observations that I have had even most recently is the issue of the various positions taken by utilities depending on the percentage of energy generated. In your particular case, according to this, you have 16,000 megawatts produced, and about 2,400 comes from coal. So that is about 15 percent.

I suspect that if you got First Energy and AEP in the same room with you they would have a different perspective on things just because of the fact of what they are burning in order to generate electricity. Just a comment that I make, and I would suspect that it is a little bit easier for you to meet some of these things than it may be for them because of their heavy reliance on coal. Would you think that that statement kind of reflects reality?

Mr. SVENSON. I think that there is a reality to that. But what I would just say is that a lot of it is not simply do I have more coal or less coal. It is a matter of some of us have already put certain controls on sooner than others. So that is another reality, is that what you will find is quite a disparity even within those who are burning coal and have different levels of control, depending on where we are in the country.

Senator VOINOVICH. The thing that would be interesting for me, just to follow up on that, I know for example, because I have this testimony from AEP, that they have spent $5 billion during the last decade. They have reduced their NO_x 84 percent. That is probably reflective, Mr. Korleski, of what you are saying, that they have done a pretty good job in NO_x. The rule could be, maybe not even tight enough for the NO_x.

On SO_2, they are at 64 percent. Mr. Schneider, I was pleased that you have indicated that they have made some real progress on SO_2. So the real issue, I think, is how do we make some sense out of this and get something done. As many of you know I have some real problems with the greenhouse gas emissions. I sometimes look at the emphasis that we are placing on greenhouse gas emissions because that is an international problem that we can impact upon.

But I also think about NO_x, SO_x and mercury, which we have some really good statistics on. One of the things that I am going to look at, and I have been thinking about doing this, is who are the people that, I think one of you said that we have 1,600 less—maybe it was you, Mr. Schneider—that died. One of you did. The issue is, where do those statistics come from?

Can you comment on that, Mr. Schneider? You have been following this for a long time. Where do we get those statistics that say the State of Ohio health care costs have increased because of bad air? Or in Ohio, X number of people are dead because of NO_x, SO_x, and mercury?

Mr. SCHNEIDER. Senator, thank you for the question. There are a number of different—actually there are hundreds of different peer reviewed published studies that relate air pollution levels to different diseases and death. There are obviously—there are both prospective studies that look at what the prediction would be. But in the last few years there have actually been retrospective studies because the air pollution has gotten less. They have been able to go back and look at the incidence of a lot of these deaths and diseases over time and tease out from that, using their methodologies, what would be attributable to the improvement in air quality.

So a lot of this is put together by, synthesized by the U.S. Environmental Protection Agency when they do a recap for you of what the benefits have been of the Clean Air Act both in the past and going forward.

So these methodologies have been reviewed both by EPA's Science Advisory Board, which involves people from industry, people from academia, environmental groups, State governments, and so forth, but also by the National Academy of Sciences. So this is all very well reviewed information that has stood the test of peer review and publication. I think our view is that it is reliable. As you heard there is a range of numbers that EPA mentioned. So there is some uncertainty involved in the absolute magnitude depending on which study you follow. That is why you saw that range in Assistant Administrator McCarthy's testimony.

But in general there is a robust set of scientific literature that helps us put some numbers on the, I would phrase it the other way, the benefits of cleaning up the air.

Senator VOINOVICH. I would appreciate it if you would share that with my office. I don't mean reports like this, but if you have executive summaries from a couple of groups I would be appreciative of your giving them to me.

Mr. SCHNEIDER. Sure.

Senator VOINOVICH. Mr. Korleski, I see you have been, this is what, your fourth year in the EPA. I remember back when I was Governor, as I mentioned in my statement or comment and when I was the former mayor of Cleveland, and I noted that somebody mentioned Cleveland is still not doing its work. Interesting to find out if it is all because of automobiles or what the cause is.

I know we wanted to get the ambient air standards taken care of as soon as possible because we did have businesses that were contemplating not expanding or even coming to the State because of the fact that we hadn't met the—and that meant they would have to expend more money in order to do business in the State.

The question I have is, from your perspective, or maybe from, and I am sure you pay attention to the economic impact these have, and you just said you met the 1997 standards?

Mr. KORLESKI. Yes, that is correct.

Senator VOINOVICH. What impact, if any, has this had on Ohio's economy and on its ratepayers? And I guess the next thing would be is that you have a little problem with the timetable of implementing these. I would also be interested in your perspective on that. So what has happened in terms of what we already are doing, and then if you look down the road, what impact do you think that has on our State? The reason I mention it is because, as you well know, we are one of the leaders in the United States in unemployment.

Mr. KORLESKI. Thank you, Senator. First, may I also say thank you for your many years of service. I have always very much enjoyed working with you. I very much respect the work that you have done in the U.S. Senate. Thank you very much, and I shall personally miss your services.

In answering your question, even 5 or 6 years ago, as I think I mentioned, it was considered unthinkable that Ohio, and in particular the Cleveland and/or Cincinnati corridors would be able to achieve the 1997 Ambient Air Quality Standard. We finally did it, I think, for a number of reasons. Certainly one was putting controls in over time, changing our rules to reflect more stringent requirements on VOCs, on volatile organic compounds. I think it is because you are seeing cleaner auto fleets. There is no question that transportation has historically been an enormous source, a contributory source to the ozone problem. And I think we are seeing our fleet slowly get cleaner, which is wonderful.

Frankly, I think, if I look back at the summer when the gas was $4 a gallon, perhaps people were driving less and that made a difference. I think it is probably a whole suite of factors that allowed us to get the point where we are today. But there is no question that a lot of it has been more stringent rules, additional controls on VOC sources, enforcement actions to get people to comply with those VOC rules, certainly both Federal and State enforcement actions. It took a number of things to get there.

The biggest point that comes to mind when you raise that issue is, while I am absolutely delighted to have finally achieved the 1997 standards State-wide, I am also troubled—that is probably not the right word—I feel somewhat whipsawed by the fact that back in 2008 there was a lower standard promulgated, and we expected there would be a lower standard. We certainly, I think Ms. McCarthy is right, the Clean Air Act requires that the standard be reviewed and amended as appropriate every 5 years.

So in 2008 the standard was lowered to .075, if I'm remembering my numbers correctly. And we were just beginning to gear up to figure out, what do we do now? More VOC controls? Let's look at the transportation sector, et cetera.

Then shortly after—and this is not about politics at all—but shortly after the new Administration took place, there was a decision that that needed to be reviewed. Based on a number of reasons it was reviewed, and I believe my colleague, Mr. Schneider, is right, that it is likely here when they propose or when they finalize a standard it will be considerably lower than the 2008 standard.

The difficulty that that places on Ohio, which undoubtedly is a heavy coal State, and you and I both know that, but the difficulty that that places on Ohio when you are changing standards that rapidly is we never have enough time. And I think industry and other regulated entities don't have enough time to get their feet clearly on the ground to figure out where are we going, what are we going to have to do, let's get a plan, let's move forward, let's fix this and meet the standard.

It is difficult when you are constantly being asked to hit a moving target. I think anyone who has ever tried to any sort of a business, any sort of a regulatory agency, or anything realizes when you are hitting moving targets you are never on solid ground; you don't know exactly what is coming next, how soon will it change again, what are we going to have to do, are we going to have start over, are we just going to have basically toss out our older implementation plans, even plans that we had submitted just a year or two ago, et cetera. It creates great uncertainty across the board, uncertainty which hampers my ability to regulate effectively, uncertainty which hampers businesses' ability to function with a predictability and certainty that we all hear about so often.

It also presents great economic uncertainty in terms of, for businesses, OK, what is going to happen in that State? Are those counties going to be in attainment or non-attainment? If they are non-attainment the issues that you raised a moment ago are still very much with us. Businesses are reluctant to locate or expand in non-attainment areas because it is more difficult. It is becoming more difficult to find the offsets. It is becoming more difficult and more expensive, certainly, to put on the additional controls that you would need in a non-attainment area.

But I think with all that, again, I go back to the biggest problem that I struggle with as a director, is continuing uncertainty about where the Federal and consequently the State regulatory system is heading. What are the rules that we are going to live by? You commented earlier and pointed out a portion of my testimony where I suggested a 10-year timeline before we started changing budgets. Maybe 10 years is too long. I am happy to talk to Ms. McCarthy and anybody else about that.

But if you talk about proposing or finalizing a standard and then within some very short period of time changing it again because of a change in the National Ambient Air Quality Standard, again we will continue to have this whipsaw effect, this uncertain foundation that everybody is trying to operate on. It will cause great confusion.

And Senator, I will be very candid. I am the EPA Director of the State of Ohio. It is first and foremost my responsibility to protect the public health and welfare and to protect the environment. That is my job. But having gone through and still living through the recession that we are seeing in Ohio, and seeing those very real-world impacts with respect to job losses and unemployment and families being unable to hold body and soul together and children being unable to have appropriate nutrition and to be educated properly, et cetera, I view that my job as a director, I have to take those real-world economic considerations into effect, well, I am not doing my job.

I can be as theoretical as I would like to be, I can look at as many epidemiological studies and as many modeling activities as I can. But at the end of the day I have to look at what is happening on the ground in Ohio, and do people understand what the ground rules are, do they know where we are going. If the answer to those questions is no, I think we all suffer.

I am sorry, that is a very long, long way around to answering your question, but I think that is how I would address it.

Senator VOINOVICH. I would be interested, and Senator Carper has left the gavel to me, but you have heard Mr. Korleski's testimony, all the other three witnesses. I will give you an opportunity to comment on what he had to say, and then we will end the hearing.

Mr. SVENSON. Senator, if I could make a comment on Mr. Korleski's comments.

Senator VOINOVICH. By the way, one of the things that maybe I can get the staff to do, I would be interested in knowing how many other States find themselves in the predicament that you do, and that is that you did the 1997, then the 2008 came out, and that was lower. And now there is some revision of that in terms of their respective SIPs because you have to put the SIP together. It takes a long time to do that. Then you get the SIP done, and then somebody comes along and says, hey, we changed this; it is going to be lower. Then you have to go back and again look at the SIP to figure out how do you get it done.

Mr. SVENSON. Senator, just a comment on Mr. Korleski's comments. First of all, New Jersey, most of the Northeast, where I am from, has been persistently into a non-attainment situation. Just to put it into business perspective, there is a provision in the Clean Air Act that is called section 185. It is a fee provision that says if you were in a severe or extreme non-attainment area back in the original 1990 Act amendments for ozone, if you didn't meet the attainment deadlines that were spelled out in the 1990 Act that there would be fees imposed, so much per ton per each source. It was $5,000 per ton, modified for a cost index.

Today, even though the EPA is not yet collecting that or the States are not collecting that because that is a requirement that is in the, at least in the Act, there have been some court cases from California on this, we have looked, as a company, at a reserve for this. It is to the tune of about $6 million to $8 million a year, and we have been doing so for the past 2 years. That is a hard, real fact of being in a non-attainment area as to what it means.

There are other businesses that are also NO_x emitters and VOC emitters. They are likely booking the same in our State as well as other States that had severe or extreme ozone non-attainment.

So that is why there is a real, you asked a while back about perspective, why do I hear different views from different utilities. It is not just simply the makeup of our fleet, but it is also where we are located. Nobody wants to be in a non-attainment area. There are not just simply the heath-based issues. There are economic issues. That is significant.

But quite frankly, your State is contributing to my State's nonattainment. And you are causing jobs to flee my State. And they are hurting the Northeast. So said directly, when you are not doing what we think is required under the Clean Air Act you are hurting my State and making it more difficult and causing unemployment to occur.

Put another way, too, we are talking about jobs. A lot of these control requirements are going to require retrofit of technologies. At the height of Mercer and Hudson's construction for the back-end technologies of scrubbers, SCRs, bag-houses, the height of construction over a 3-year period, 1,600 construction jobs, I would suggest, by the way, 25 permanent operating positions have been created at each one of those coal plants for the back-end control technology.

So there are, yes, there are costs in terms of costs borne in rates. The flip side of that is there are jobs created, needed construction jobs, as a result of this. I do agree with Mr. Korleski's comment about whipsawing. There has to be some certainty. I believe that the Assistant Administrator has really reached out to try over the past year to bring in the industry, Department of Energy, FERC, and others in the environmental community to anticipate what these emerging requirements are going to be to provide a road map. And actually it is some of our members of industry and others that have actually created some of the uncertainty because of the litigation and other things that have actually derailed what otherwise would have been in place by now.

Senator VOINOVICH. Well, the argument on that might be that because of the fact that they feel that it is arbitrary, that they go to court in order to do it, and if they felt that it was less arbitrary and had more time they might not be going into court.

I am very familiar with what you are talking about. I was Chairman of the National Governor Association. One of the biggest mistakes I made was to put Christine Todd Whitman in charge of the environment when I was with the NGA. There has always been this problem that Ohio is responsible for our situation.

I thought that when we came forward with the Clear Skies that there was some understanding that that would eliminate the need, I think what are they, 126 petitions that the States file that they are saying, they have to file a petition in order to kind of say to the EPA, our problem, we are not creating our problem, somebody else is doing it, and kind of give them some relief. I thought at that time, the way it all worked out, that that would have eliminated some of what you are talking about.

Does anybody want to comment on that?

Mr. SNYDER. I was actually going to respond to the previous question and respond to some of the comments.

Senator VOINOVICH. The point is that the issue here is that you have States that feel that they are being penalized because other States aren't doing what they are supposed to be doing. I guess in Ohio we could argue that maybe we have problems because of Gary, Indiana, or whatever. Everybody is being impacted, and you would argue that you are being more impacted than Ohio is from air transport.

So the point is, how do you work that out?

Mr. SNYDER. I think we are beyond the point of State versus State in this. I think some of the maps that you see show that now we are all in this together. And we all need to do our part to reduce emissions, to provide the benefits of clean air to all of our residents. EPA has an obligation to set air quality standards that protect public health. And we take that seriously, just like Mr. Korleski.

It is my job, it is my boss's job, Commissioner Pete Grannis, to achieve, to meet those standards, to protect the environment of our people. That can be a difficult job when EPA lowers the standards—as we are already controlling the smallest products, consumer products, small sources—to find additional ways of getting the emission reductions. But we take that seriously, we do that.

But what I think EPA recognizes with this Transport Rule is that we need the reductions on a regional basis, and it benefits all of us. It benefits us in New York if there are emission reductions in Ohio and Pennsylvania and New York. And as that map shows it benefits the people in Ohio, Pennsylvania, and New York also.

It is a hard job to keep up with EPA's standards. But EPA has its job, and we have our job. And so far we have succeeded in doing it.

I would like to make just a couple of points about the certainty question that has been raised a couple of times. This Transport Rule leaves many of the large sources uncontrolled. And so when EPA takes the next step and promulgates another transport rule, that is not going to mean additional controls on a plant that already has a scrubber and already has SCRs in place. It means the next plant will put scrubbers and SCRs on its facility to control emissions.

So I don't think that the certainty issue is really that much of a problem.

One final point on certainty is I think the best way of providing certainty is aligning all these obligations. EPA is doing a good job of that, especially with coming out with the mercury rule next year. I think the missing piece is climate. If Congress passes a climate bill then industry knows with greater certainty what the future holds, and it can make those investment decisions for the next 20 or 30 years with more certainty.

Senator VOINOVICH. Mr. Schneider, then we will wrap it up.

Mr. SCHNEIDER. Senator, I really couldn't add anything to what my colleagues have done. They have done a great job of explaining this issue. I guess, speaking to someone who is from Ohio, I would just say that Ohio stands to benefit the most from this, and I think it is in part because of what you said that this transport into Ohio from other States. I urged EPA to provide for this hearing a great map, which shows, we have a mental image in our mind that the air always blows from Ohio up to the northeast, that sort of the end of the tailpipe thing. But in fact, and that is the way weather systems move.

But when there is a bad air day the systems as you know also are cyclonic. If you look at the weather maps, everything is in a circle. We are breathing all the same air in one big pool. And what actually gets emitted in the mid-Atlantic States blows back into you.

So what Mr. Snyder said is exactly right; we are really all in this together, and I hope we can get past the idea that it is a blame game and look at these provisions as a good neighbor policy. We are close, as these maps show. We are very close to a solution for a lot of this. I think if we can move incrementally forward to tighten the Transport Rule or to pass the legislation that you and Senator Carper have been working on and crafting, we can meet a lot of the objectives that we have been working on for over a decade.

Senator VOINOVICH. I want to thank the witnesses for being here today. It has been enlightening for me. Thank you.

[Whereupon, at 11:25 a.m., the Subcommittee was adjourned.]

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