

The Effect of Input Assumptions on the Results of IPM Modeling Runs Used to Predict Future Pollutant Emissions

By: Julie McDill and Patrick Davis of MARAMA

8600 LaSalle Road Suite 636

Towson, MD 21286

jmcwill@marama.org

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ABSTRACT

Regional haze and fine particle pollution in the eastern U.S. are currently dominated by sulfate pollution, and the principle sources of SO₂ emissions contributing to sulfate are the large coal fired installations in and near the region, including electric generating units (EGUs). The U.S. Clean Air Interstate Rule (CAIR) introduced a cap and trade approach to controlling air emissions in the eastern U.S. Under this rule EGU emissions are constrained by the price of pollutant allowances rather than firm permit limitations. This introduces new uncertainty into the task of forecasting future EGU emissions. IPM® is a least cost model used extensively by both regulators and the regulated community in the United States to predict Electrical Generating Unit operating schedules and the resulting air emissions resulting from that operation. These predictions can vary widely depending on the assumptions used in a particular modeling study. Important assumptions include the price and availability of both fuel and control technology, and the controls installed for other reasons outside the emissions trading scheme. This paper will compare modeling studies that use different sets of plausible inputs. State by state and regional variation will be discussed. The comparison will provide an indication of the range of outcomes that might be expected by 2018, thus assisting policy makers in evaluating the likelihood of predicted fine particle pollution and visibility outcomes.

INTRODUCTION

State and Federal air agencies use estimates of future emissions of air pollutants for a variety of planning purposes. For example, agencies use such estimates as inputs to air quality models to confirm that a proposed industrial expansion will not result in an exceedance of National Ambient Air Quality Standards. In other situations, future emission estimates are used to understand the outcomes of competing strategies and policies that might be employed to meet an air quality goal. The emissions estimates resulting from a selected control measure may be included in a State Implementation Plan (SIP). In this circumstance, the state may be required to enforce the installation of individual controls to meet the emissions estimates contained in the SIP.

Emissions from Electric Generating Units (EGUs) are typically predicted based on engineering economic models. These models predict the effect of a number of regulatory and market drivers on the many choices made by merchant power generators and utilities to provide power to the nation. These choices are then translated into source-by-source air pollutant emission estimates. One model that has been employed widely for this purpose is the Integrated Planning Model® (IPM®) developed by ICF (EPA 2005) has been used by the U.S. Environmental Protection Agency (EPA) for over 10 years to

project the impact of emissions policies on the electric power sector. The IPM® model was used by EPA in developing the Clean Air Interstate Regulation (CAIR) and the Clean Air Mercury Rule (CAMR).

IPM® is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It forecasts least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints. Emission control options include a broad array of retrofit technologies along with emission reductions available by fuel switching, changes in capacity mix, and electricity dispatch. Finally, to develop the least cost solution, IPM® considers a variety of environmental market mechanisms, such as emissions caps, allowance trading, and banking. For example, IPM® can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of a variety of pollutants typically emitted by electricity generating units.

In 2005 the EPA finalized CAIR which caps emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) in 28 eastern states and the District of Columbia as shown in Table 1 (Federal Register 2005). Prior to CAIR EPA allocated emission allowances for SO₂ to sources subject to the Title IV Acid Rain Program. In addition, 20 states and the District of Columbia developed NO_x Budget Trading programs in response to the NO_x State Implementation Plan Call rule that was promulgated in 1998. CAIR establishes an annual cap-and-trade system for SO₂ and NO_x comparable to the systems used in these earlier trading programs. Acid Rain allowances can be used in the CAIR model SO₂ trading program.

Table 1. Final CAIR Rule SO₂ and NO_x Emission Caps (Million Tons) (USEPA 2006).

Pollutant	2010-2014	2015 and later
SO ₂	3.9	2.5
NO _x	1.6	1.3

For the trading programs, EPA provides emission allowances to each state according to the state budget included in the federal regulation. States allocate those allowances to sources (or other entities), which can trade them. Sources are free to choose from many compliance alternatives, including installing pollution control equipment, switching fuels, or buying excess allowances from other sources that have reduced their emissions. Each source must hold sufficient allowances to cover its emissions each year. It is expected that the flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment.

Cap and trade programs remove from the hands of regulatory agencies control over which sources will install control equipment. In the past government regulatory agencies could clearly commit to which sources would be controlled. As a result, modeling exercises designed to demonstrate the effect on ambient pollutant concentrations could be based on firm expectations of emissions from particular plants. In a cap and trade system, regulatory agencies only control the total emissions from all plants in the control region. The geographic and temporal distribution of emissions can be shifted by economic decisions made by the regulated community.

The question is, how sure can regulators be of the predicted emission distribution? Can reasonable differences in input assumptions in the model result in important differences in the emissions distributions? How does a cap-and-trade model affect the efficacy and implementation of other rules and settlements that are pursued by regulatory agencies?

In this paper we compare the air pollution emissions in future years based on several IPM® modeling exercises. Each modeling exercise used a well thought out set of input assumptions that were deemed reasonable at the time, including projected fuel prices, EGU characteristics and capabilities, court settlements, and state and federal regulations. The effect of these inputs on the modeling results is assessed. The interplay of traditional command and control regulations with a cap and trade system is explored.

ANALYTICAL APPROACH

A. Introduction to the modeling runs compared.

Several IPM® modeling runs were compared in this study. First, the input assumptions for each run were collected, analyzed and summarized. Then the results of the runs were analyzed and summarized. Inferences are drawn about how input assumptions affect the model results. The runs analyzed were:

- EPA 2.1.9
- RPO 2.1.9
- MARAMA 2.1.9 (5c)
- EPA 3.0

The model runs analyzed were selected because they are recent, well documented, and in the public domain. Furthermore, the runs were sequentially built with incremental changes to the input parameters. Finally, all runs included output for either 2020 or 2018 which were the two years were selected for analysis in this study. The studies prepared for EPA generally included 2020 data, while studies prepared for the regional planning organizations (RPO) generally included 2018 modeling data. In this study only common years are directly compared. This allows analysis of the effect of input assumptions on the modeling output.

The following is a description of each modeling run analyzed as part of this study.

EPA 2.1.9

EPA 2.1.9 was commissioned by EPA in an effort to assess the impact of the Clean Air Interstate Regulation (CAIR) prior to its adoption. A base case was developed and compared with a number of policy option cases. Prior modeling inputs were modified to incorporate the latest data on generating units, and input assumptions including emissions controls, and revised laws and regulations. However, this case was modeled for 2010, 2015, and 2020 but not 2018.

RPO 2.1.9

RPO 2.1.9 was commissioned in 2005 by a group of Regional Planning Organizations (RPOs) in preparation for SIP modeling. It is based on the EPA 2.1.9 run with some changes to control assumptions based on the final CAIR rules as well as additional changes to model inputs based on State and local agency and stakeholder comments.

MARAMA 2.1.9 5c

In 2007 MARAMA commissioned two runs of IPM® to evaluate a control strategy for EGUs that reduced emissions beyond current federal requirements throughout the eastern US via a tighter regional cap and trade program. These runs were based on the RPO 2.1.9 runs. MARAMA 5c is the base case,

which includes CAIR as a base assumption. MARAMA 4c includes a tighter regional cap and trade program the further reduces emissions. Only MARAMA 5c is discussed further below.

EPA 3.0

In 2006 EPA released EPA 3.0 using IPM®. This modeling platform includes extensive updates of EPA 2.1.9 assumptions, inputs, and capabilities. EPA's assumptions were reviewed by nationally recognized experts in fuels, technology, and power system operations. Power companies provided information on generating resources and emission controls. EPA also obtained input from RPOs, and States. Key update areas included:

- Coal supply and transportation assumptions
- Natural gas assumptions
- Federal and state emission regulations and enforcement actions
- Cost and performance of generating technologies and emission controls
- SO₂, NO_x, and heat rates
- Power system operating characteristics and structure
- EGU inventory
- Extension of modeling time horizon (2010, 2015, 2020, 2025)
- In 2006 EPA also commissioned additional run years, including 2018 for the convenience of RPO SIP planning.

B. Inputs that varied between the three runs

The inputs to IPM® are extensive and detailed. The changes considered in this paper are:

- Changes to fuel prices,
- Implementation of Department of Justice (DoJ) settlements and
- Changes in state and federal regulatory programs.

1. Fuel Price

The price of fuel assumed in the model is an important variable. Depending on the price of fuel, electricity generators may reduce emissions by switching to a lower emission fuel rather than adding control equipment. For example, following the passage of the Title IV Acid Rain cap-and-trade program, fuel switching to lower sulfur coal was used widely to comply with sulfur dioxide emission limits. This was unanticipated by many regulators, who had assumed that scrubbers, which can achieve between 90-95 percent reduction of SO₂ emissions, would be used to comply. However, power generation companies found that fuel switching offered an attractive option that could achieve the sulfur reduction goal more cheaply. A coal fired boiler can reduce SO₂ emissions between 50-80 percent by switching from high to low sulfur coal. Even further reductions, up to 99 percent, can be achieved by deploying gas fired generation in lieu of coal fired generators.

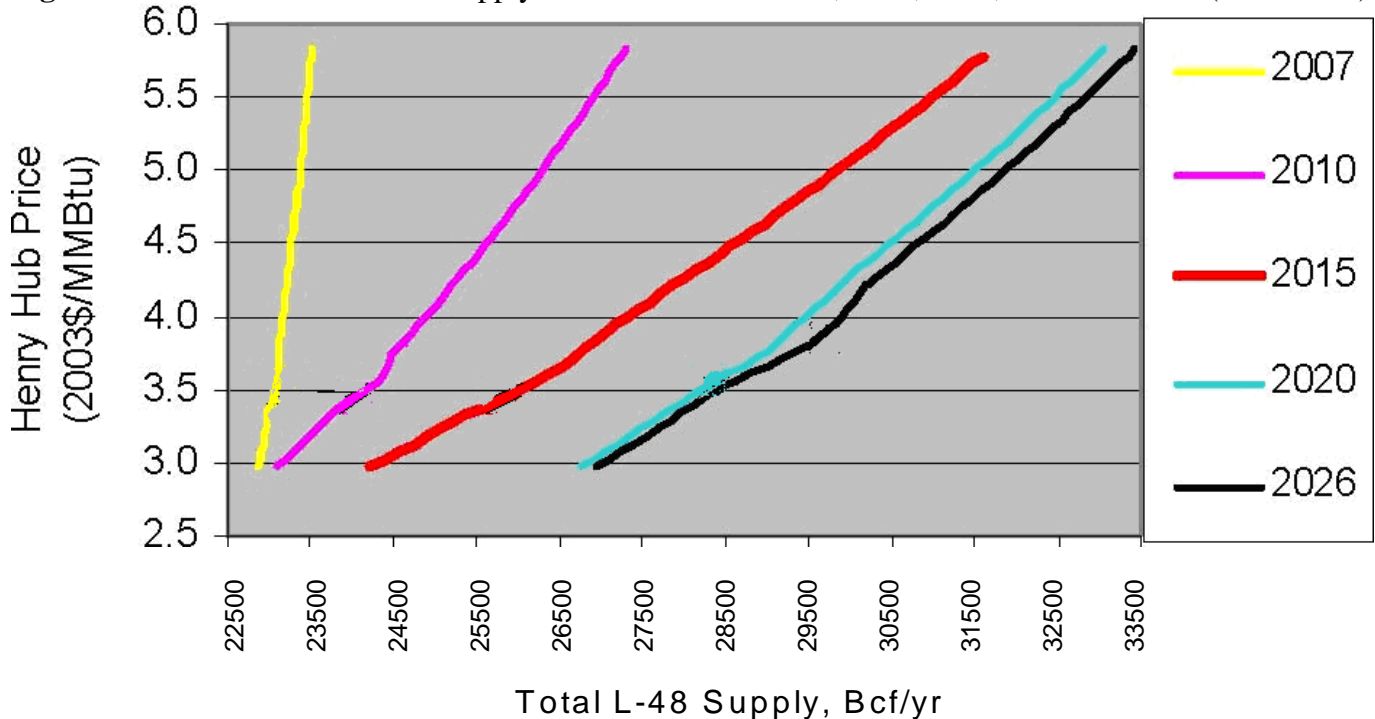
IPM® considers the options of burning various qualities of coal, biomass, fuel oil and natural gas. The more expensive the fuel, the less likely the model will select it for combustion in a given unit, all else being equal. As a practical matter coal and gas are currently the two fuels most often selected by the model, and in the real world these two fuels account for the vast majority of fossil fuel burned to generate electricity. Therefore, only gas and coal price assumptions are discussed in this paper.

The price paid for coal or natural gas depends on both production and delivery costs as well as the demand for that fuel. Supply curves are developed for each fuel source used by the model. Supply curves provide a price-quantity relationship for each fuel. As the quantity demanded for a particular fuel increases, the cost also increases. The cost point for the fuel is reached when its price reaches a point where other fuel options are cheaper and therefore are selected as the least-cost compliance option. A separate supply curve was developed for each model run year. While coal cost curves are created within IPM®; the natural gas price curves are developed using a separate model called North American Natural Gas Analysis System (NANGAS). The price of gas used in a particular run is solved iteratively by working between the two models, NANGAS and IPM®, until the demand for each fuel results in a common price. The NANGAS supply curves incorporate the price impact of demand for natural gas from the non-electric sector.

EPA 2.1.9

Natural Gas Prices: A major review and update of the natural gas supply curves was performed for EPA 2.1.9. The update was based on the recommendations of a panel of eight prominent, independent experts and a study by the National Petroleum Council. The impact of non-electric sector fuel use on price for natural gas was incorporated into the model for the first time. A fixed price elasticity of -0.5 was used to represent the affect of price on demand for natural gas by non-electric sectors. Figure 1 shows the Natural Gas supply curve used in EPA 2.1.9.

Figure 1. EPA 2.1.9 Natural Gas Supply Curves for Years 2007, 2010, 2015, 2020 and 2026 (EPA 2005.)



Coal Prices: EPA 2.1.9 retains the coal-supply curves and transportation cost assumptions used in the earlier modeling platform, EPA 2.1.6. However EPA commissioned a major review by coal experts of the coal choices offered to specific generating units (EPA 2005). As a result of this study updates were made to coal assignments in EPA 2.1.9 to enable better capture of recent developments in the use of coal.

RPO 2.1.9

Natural Gas Prices: RPO 2.1.9 used the same assumptions for natural gas as EPA 2.1.9.

Coal Prices: RPO 2.1.9 used the same assumptions for coal prices as EPA 2.1.9.

EPA 3.0

Natural Gas Prices: For EPA 3.0 prices paid for gas in various markets were reviewed and NANGAS was updated to reflect recent trends. In some locations this resulted in a higher price; in others the price was lowered. Overall the updates to NANGAS gas curves resulted in a 40-60 percent higher gas price in EPA 3.0 as compared to EPA 2.1.9. The average lower 48 state gas price increased from approximately \$4/MBtu to \$6/MBtu.

Important modeling scenario updates that affected the price of Natural Gas are as follows:

Production Decline Rate for Existing Wells - Reduced production from existing wells results in increased production from higher cost gas resources. This makes the NANGAS near-term price forecast more consistent with recent higher gas prices.

Near Term Price Elasticity for Residential and Commercial Gas Demand – The near-term price elasticity in the residential and commercial sectors was reduced. This means that there will be a lag in the system, initially consumers will reduce consumption slightly in response to increased price and later, if the increased price persists, consumers will respond by reducing consumption more sharply.

LNG Supply – The LNG trigger price, which is the minimum acceptable price for landed LNG at a receiving terminal, was revised. In EPA 3.0 gas supplied by LNG terminals is assumed to grow significantly. Currently, only 4 percent of the Lower-48 natural gas demand is met by LNG imports. The share is expected to reach 17 percent in 2015 and 20 percent in 2025. On average, about half of the LNG imports will come through terminals in the Gulf Coast where throughput will grow from 0.5 Bcf/d in 2005 to more than 8 Bcf/d in 2025. Based on EIA information on potential new LNG terminal capacity EPA 3.0 predicts that new terminals in Baja, Bahamas, Crown Landing, and Bear Head will be operational sometime between 2008 to 2015, each with up to 1 Bcf/d send-out capacity. Total volume of LNG imports to the Lower-48 is expected to reach more than 14 Bcf/d in 2025.

Coal Prices: New coal supply curves and a new transportation cost matrix were developed for EPA 3.0 based on a study by a team of fuels experts (EPA 2005). The result is a significantly higher coal cost in EPA 3.0 than in either EPA 2.1.9 or RPO 2.1.9. This cost increase averaged \$0.40/Mbtu or about 40 percent. However, as can be seen in the previous section, this increase is much less than the price increase for natural gas. Therefore gas usage is relatively penalized in EPA 3.0, making it a less attractive alternative for reducing EGU emissions.

MARAMA 5c

Natural Gas Prices: The higher gas supply curves developed for the EPA 3.0 were used in the MARAMA analysis. As mentioned earlier, these curves result in a 40-60 percent higher gas price as compared to the EPA 2.1.9.

Coal Prices: The MARAMA 5c runs retain the coal-supply curves and transportation cost assumptions used in the earlier EPA 2.1.9 rather than the higher coal costs developed for EPA 3.0.

Summary of the Fuel Cost Modeling Input

Table 2 summarizes and compares the delivered prices resulting from the combination of fuel demand and the price curves developed for that run. In general for all runs, the delivered cost of fuel is approximately three times higher for gas than for coal. This means that the avoided cost of controls made possible by burning gas must be substantial to justify the price paid for that fuel.

Table 2. Comparison of Delivered Fuel Costs in Lower-48 in Four IPM® Configurations.

Run Name	IPM Version	Coal Cost (1999\$)		Gas Cost (1999\$)	
		(\$/MMBTU)	Ratio *	(\$/MMBTU)	Ratio *
EPA Base Case 2004	2.1.9	1.05	1.00	3.34	1.00
MARAMA Base Case 5C	2.1.9 w/ 3.0 Gas Curve	1.07	1.02	4.82	1.44
MARAMA Policy Case 4C	2.1.9 w/ 3.0 Gas Curve	1.06	1.01	4.88	1.46
EPA Base Case 2006	3.0	1.41	1.34	5.38	1.61

* Ratio of Fuel Cost in current case to EPA 2.1.9

In Table 2, the column titled “Ratio” compares the fuel cost for a particular run with the cost experienced in EPA 2.1.9. Updates for EPA 3.0 resulted fuel price increases for both coal and gas with coal experiencing a 34 percent increase and gas experiencing a 61 percent increase in delivered price. The MARAMA 5c and 4c runs used coal cost curves from EPA 2.1.9 and gas curves from EPA 3.0.

2. Consent Decree Settlements and Promulgation of New Regulations

State and federal regulations are constantly being developed and revised. Each version of the model has incorporated the regulations existing at the time of development that affect the electricity markets. In addition, both state and federal justice departments have been pursuing litigation against non-compliant companies, and in recent years this has resulted in significant control retrofits on EGUs. This is particularly true for New Source Review (NSR) settlements. Table 3 summarizes NSR settlements that have been incorporated in the runs considered in this paper.

New Source Review Consent Decree Settlements

As can be seen in Table 3, NSR settlements in recent years have resulted in emission reductions from the affected sources. In addition, some of the settlements have required the surrender of SO₂ emission allowances so that the reductions cannot be traded to other sources via the allowance trading system. However the allowances surrendered are much less than the SO₂ removed. Therefore, in most cases the firm owning the allowances will retain the right to sell them to others and the emissions will be simply be displaced to EGUs at other locations. In this case there is no net national decrease in emissions as a result of the settlement. If the settlements are concentrated in a single region of the country, on average that area will experience a decrease in EGU emissions while other areas of the country will experience an increase in emissions.

As can be seen in Table 3, in each successive implementation of IPM® finalized NSR settlements are added to the model.

Table 3. NSR Settlements with Tradable Allowances under CAIR.

Company	Date of Settlement	SO2 Removed (1)	Allowances Surrendered	EPA 2.1.9	RPO 2.1.9	EPA 3.0
TECO	2000	70,000	Excess allowance to be retired	Yes	Yes	Yes
PSEG	2002	35,937	Excess allowance to be retired	Yes	Yes	Yes
VEPCO	2003	176,545	45,000 Per year	Yes	Yes	Yes
WEPCO	2003	65,053	Excess allowance to be retired	Yes	Yes	Yes
SIGECO	2003	6,384	Excess allowance to be retired	Yes	Yes	Yes
SANTEE	2004	39,014	None	Yes	Yes	Yes
Illinois	2005	39,014	Scaling up to 30,000 Per year	no	Yes	Yes
Ohio Edison	2005	171,500	None	No	Yes	Yes
Alabama Power	2006	22,788	7538 One time	No	No	Yes
Minnkota	2006	23,600	Scaling up to 14,886 Per year	No	No	Yes
Mirant Mid-Atlantic	2006	Unknown	None	No	Yes	Yes
Nevada	2007	None	Unknown	No	No	No
East Kentucky	2007	48,000	Unknown	No	No	No
AEP	2007	654,000	Unknown	No	No	No
TOTAL		1,351,835				

(1) Tons of SO2 removed as a result of controls required by the settlement as per Jim Lofton, DoJ lawyer responsible for NSR litigation as provided in a slide given a presentation at Johns Hopkins Seminar March 2008.

State Consent Decree Settlements

Apart from the EPA consent decree settlements, states also pursue suits against noncompliant companies. Several settlements are included in EPA 3.0 which reduce emissions from particular EGUs. However, since, in most cases, no allowance surrenders are implemented as part of these settlements, the net result is to redistribute emissions away from the affected units and toward other EGUs that can purchase the allowances no longer needed for these units. As long as the CAIR caps remain in effect, no net national reduction in emissions will occur as a result of these settlements although the emissions may be redistributed.

3. Summary of Modeling Output

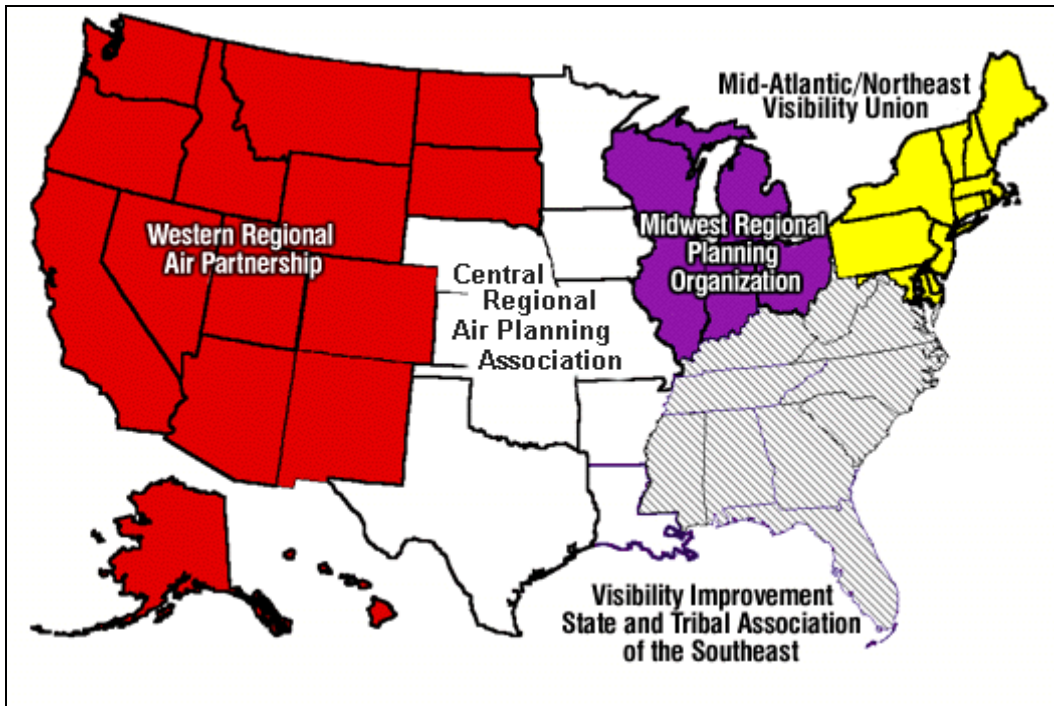
Emissions in this study are generally aggregated by regions using the boundaries of RPOs. These RPOs are as follows:

- Mid-Atlantic/Northeast Visibility Union (MANE - VU) – Northeastern and Mid-Atlantic United States. Including Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.
- Visibility Improvement State and Tribal Association of the Southeast (VISTAS) – Southeastern States. Including Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia and the Eastern Band of the Cherokee Indians
- Midwest Regional Planning Organization (Midwest RPO) – Midwestern United States. Including Illinois, Indiana, Michigan, Ohio, and Wisconsin.

- Western Regional Air Partnership (WRAP) - Western United States. Including Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, Wyoming.
- Central Regional Air Planning Association (CENRAP) - Including Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana.

Figure 2 graphically shows the location of each of these regions.

Figure 2. Regional Planning Organizations.



From: EPA Website located at: www.epa.gov/visibility/regional.html

RESULTS

A. Effect of Changing Input Assumptions on National Emissions

Both EPA 2.1.9 and 3.0 predict that the implementation of the CAIR rule will result in a large reduction of NO_x and SO₂ emissions. This can be seen in Figure 3 where national SO₂ and NO_x emissions predicted for 2020 are compared with and without the implementation of CAIR caps. Without CAIR, annual 2020 NO_x emissions nationwide would be 3.7 million tons and SO₂ emissions would be 8.9 million tons. By implementing CAIR, 2020 annual emissions of NO_x and SO₂ are expected to drop almost in half to approximately 2.2 million tons and 4.5 million tons respectively.

B. Effect of Changing Input Assumptions on CAIR Region Emissions

Figure 4 presents emissions projected by EPA 2.1.9 and 3.0 for the CAIR region with and without the CAIR caps. Once again, a nearly twofold reduction in emissions is expected as a result of CAIR implementation. However, while significantly reduced, predicted SO₂ emissions for 2020 with CAIR

Figure 3. Comparison of Predicted 2020 SO₂ and NO_x EGU Emissions with and without CAIR Caps Nationwide.

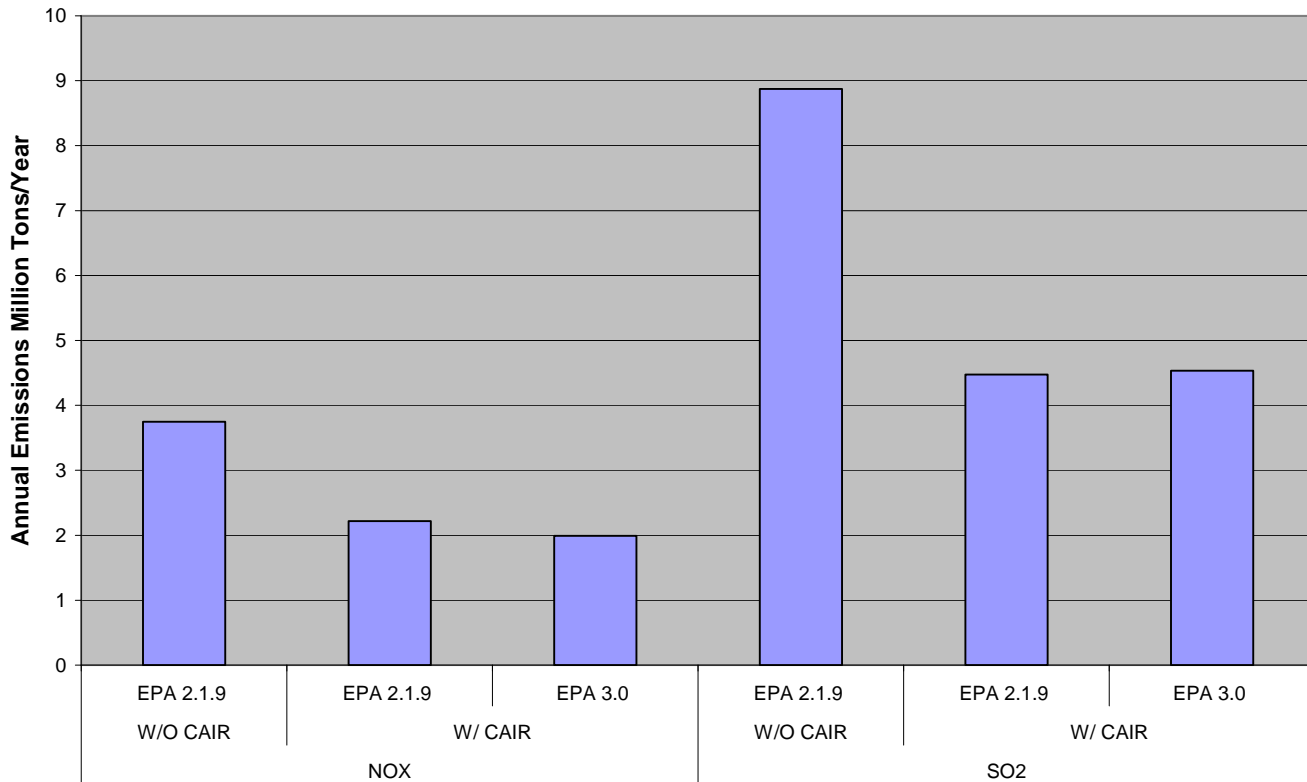
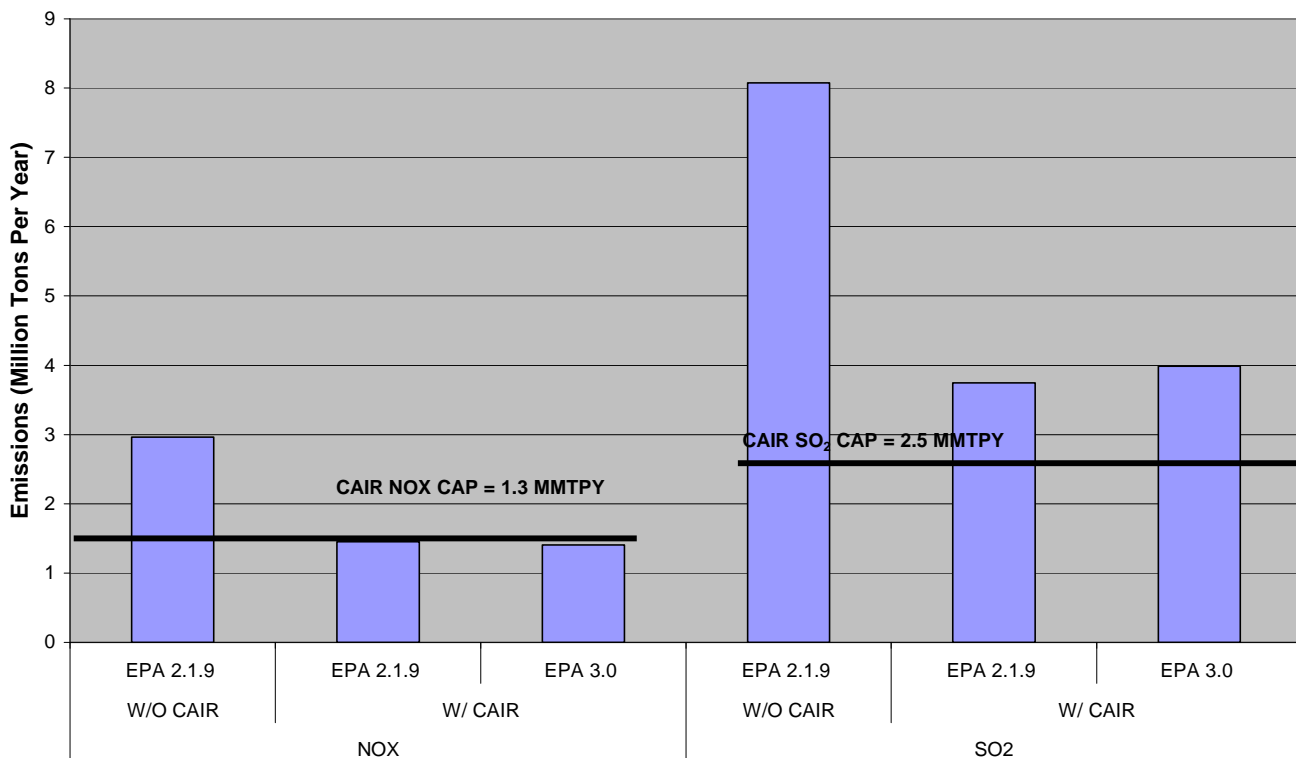


Figure 4. Comparison of Predicted 2020 SO₂ and NO_x EGU Emissions with and without CAIR Caps in the CAIR Region



implementation are higher than the CAIR caps of 2.5 million tons set out in EPA regulations. This is because emissions banked under the Title IV Acid Rain program will still be in circulation and can be emitted in lieu of controls. Conversely, NO_x emissions predicted for 2020 are lower than the Federal CAIR cap of 1.3 million tons. No comparable NO_x emission bank exists as part of the Acid Rain program. (Federal Register 2005)

The other assumptions considered, such as fuel prices, state and federal rule implementation, and NSR settlements, do not significantly affect predicted total SO₂ and NO_x emissions in the CAIR region as a whole. This can be seen by comparing the EPA 2.1.9 and 3.0 bars with CAIR shown in Figure 4. EPA 2.1.9 annual SO₂ emissions are only a 3 percent or 48 thousand tons higher than EPA 3.0. Predicted 2020 annual NO_x emissions increase by 6 percent, or 238 thousand tons, between EPA 2.1.9 and EPA 3.0.

Total predicted emissions both nationally and in the CAIR region do not change between the two modeling platforms because meeting the CAIR caps is the overarching goal set within the modeling and regulatory structure. Therefore reductions that are achieved by control of particular sources through regulation, legislation, or legal settlement (such as the NSR settlements) make no difference to total emissions. These regulatory drivers might result in the freeing up of allowances that can be sold to other participants in the cap and trade system and are then emitted elsewhere in the region. While changes in these assumptions result in significant differences in the cost to comply, they did not have any appreciable effect on total emissions within the CAIR region or nationwide.

C. Effect of Changing Input Assumptions on Regional Distribution of Emissions

While the predicted total national emissions are largely unaffected by input assumptions, the geographic distribution of emissions is significantly altered by changing assumptions. Figures 5 and 6 show that total regional emissions are shifted as a result of the modified input assumptions.

Figure 5 compares the modeled SO₂ emission results from the input assumptions used in RPO 2.1.9, MARAMA 5c, and RPO 3.0. RPO 2.1.9 predicts SO₂ emissions to be 15 percent lower on the eastern seaboard (MANE-VU and VISTAS regions) when compared to RPO 3.0. Conversely, RPO 2.1.9 predicts SO₂ emissions to be 20 percent higher in the Western United States (WRAP and CENRAP) when compared to RPO 3.0. In the MWRPO emissions of SO₂ decline very slightly by less than 5%. In other words, although total emissions remain relatively unchanged nationwide for the two scenarios, regionally, SO₂ emissions are shifted from the Western states to the Eastern States.

Figure 6 compares the modeled NO_x emission results from the input assumptions used in RPO 2.1.9, MARAMA 5c, and RPO 3.0. RPO 2.1.9 and 3.0 predictions for NO_x agree for states on the eastern seaboard (MANE-VU and VISTAS regions) and the Midwest (MWRPO). Conversely, RPO 2.1.9 predicts NO_x emissions to be 20 percent higher in the Western United States (WRAP and CENRAP) when compared to RPO 3.0. In summary, when comparing the two scenarios on a nationwide basis in 2018 overall NO_x emissions drop slightly. However, this drop occurs only in Western states, resulting a significant difference in NO_x emissions between scenarios for that region.

Differences in modeling inputs resulted in significant differences in emissions distribution. However, the redistribution cannot be attributed to NSR settlements. This is because most of the plants involved in settlements that were accounted for in RPO 3.0 but not in RPO 2.1.9 are located in the Midwestern United States. Emissions in the Midwest (MRPO) are very similar for all modeling runs compared. For SO₂ emissions declined very slightly (less than 5% difference) and NO_x remain the same.

Figure 5. 2018 Regional SO₂ Emissions Predicted by Three Modeling Runs.

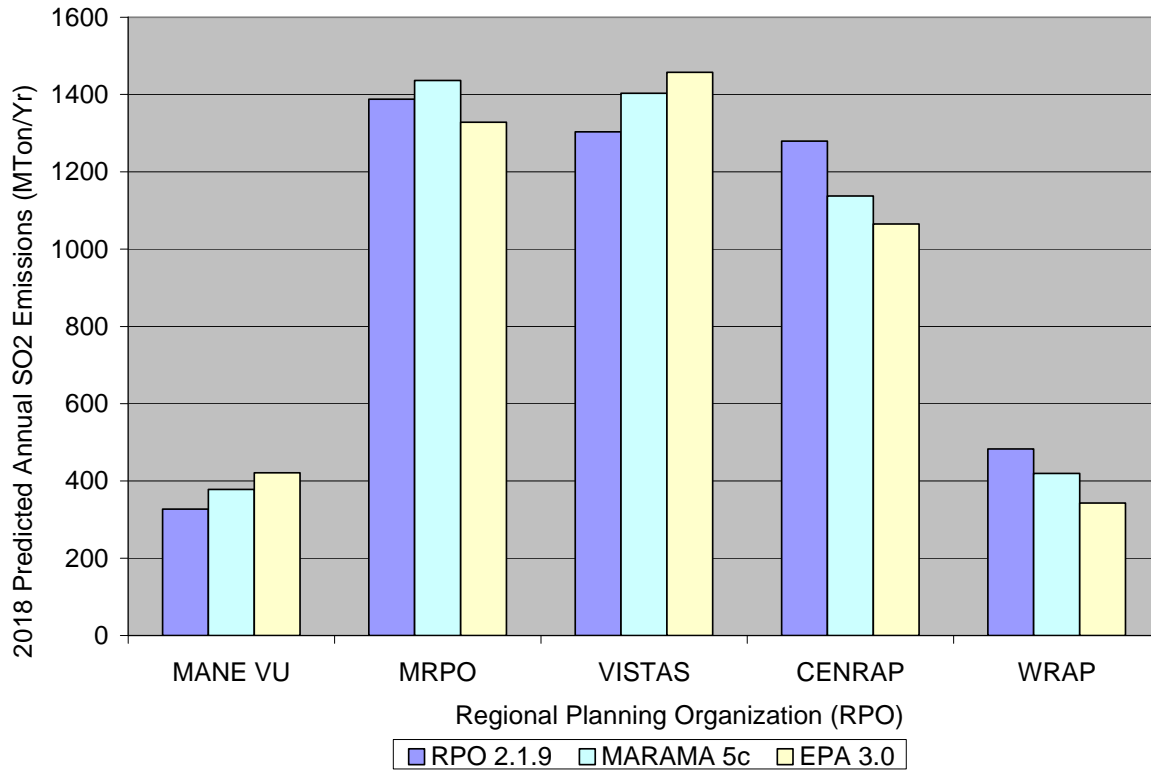
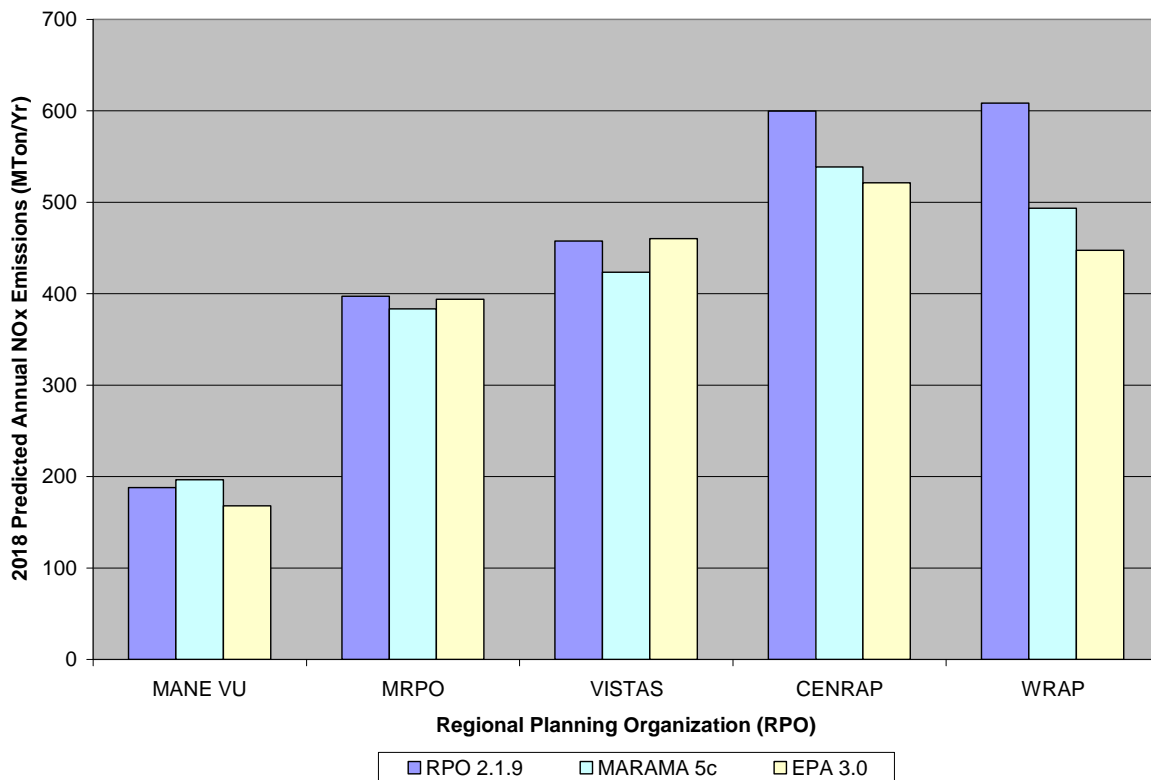
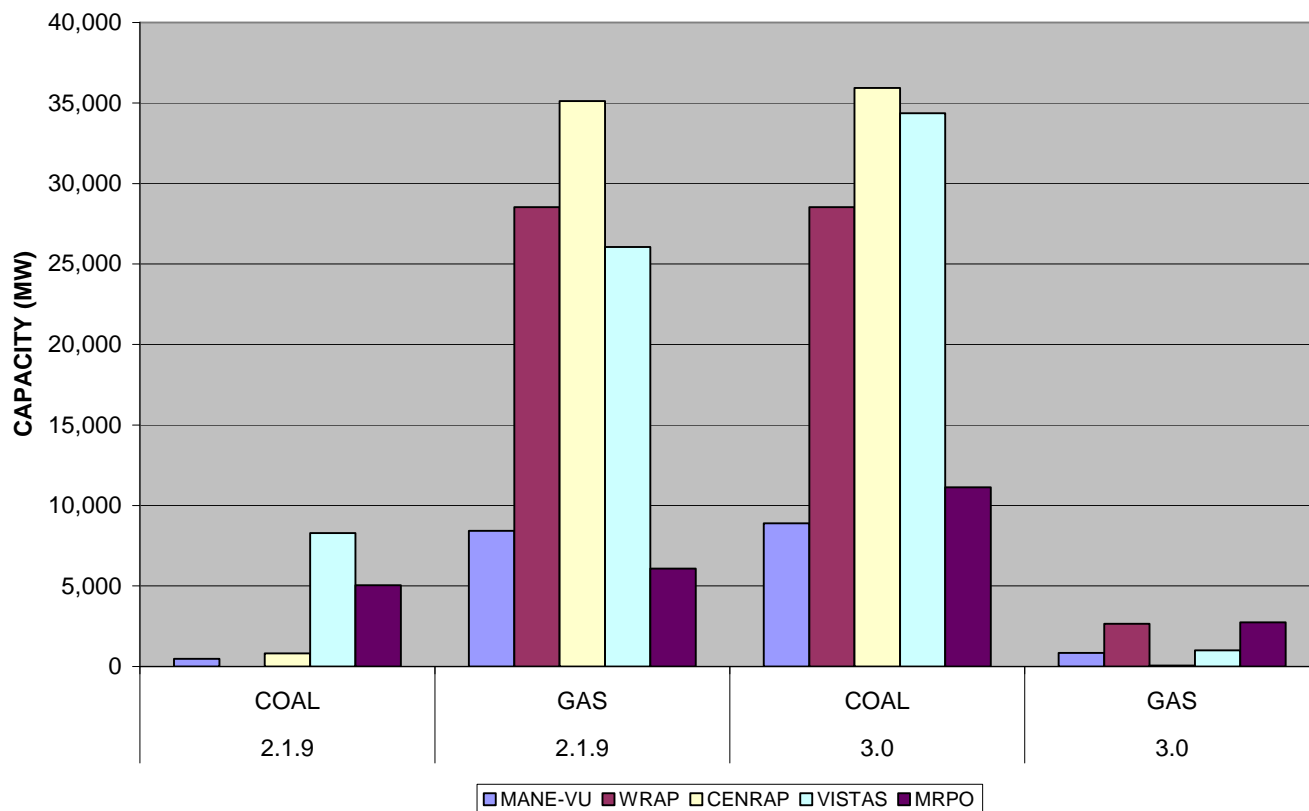


Figure 6. 2018 Regional NO_x Emissions Predicted by Three Modeling Runs.



An important change in input assumptions between the runs is the price of fuel. Fuel prices are 40 percent higher in EPA 3.0 when compared with RPO 2.1.9. Gas prices escalated from \$3.34/MMBTU to \$5.38/MMBTU while coal prices escalated from \$1.05/MMBTU to \$1.41/MMBTU. This change affects the choice of design of newly built plants. Economic considerations will favor the construction of gas plants in RPO 2.1.9 while coal will be favored over gas in 3.0. The difference is drastic as can be seen in Figure 7.

Figure 7. 2018 Comparison of New Build Fuel Choice in RPO 2.1.9 versus IPM 3.0.



In summary, input assumptions drastically affect the type of fuels used in new capacity and the distribution of emissions regionally. In RPO 2.1.9 fuel switching to gas is a strongly preferred method to achieve compliance with the CAIR caps. In EPA 3.0 gas is not often the selected fuel because of its relatively high price.

IMPLICATIONS

There is an important disconnect between the two general types of air pollution regulations currently in effect in the United States today. These two types of regulations are the more traditional “Command and Control” regulations that impose specific requirements on specific sources or classes of sources and the more recently adopted “Cap and Trade” regulations that set overall standards for total emissions but allow individual sources considerable latitude in selection their method of compliance. Of special interest is the effect of the CAIR rule and legal settlements under NSR. These actions are specifically taken to improve air quality. However, as can be seen in Figures 5 and 6, on a nationwide and CAIR regional basis the effect of these actions is minimized when they are taken within a Cap-and-Trade system. This is a concern because it requires significant state and federal resources to enact and

enforce regulations or pursue legal action. Not only do the actions have little effect on total emissions but they could also have the unintended effect of dislocating emissions from one locality to another within the region.

One approach that could reverse this trend is to consider retirement of emission allowances that result from such actions. For example, as can be seen in the NSR settlements shown in Table 3, that were settled between the development of EPA 2.1.9 and EPA 3.0, annual reductions of more than 300 thousand tons of SO₂ emission occurred at individual sources. If allowances were entirely retired from the CAIR cap as part of the settlement this could have resulted in significant regional emission reductions. Reductions did not occur because the settlements only contain limited requirements to retire emissions allowances. This result was also reported by the National Academy of Sciences in a study intended to consider the impact of CAIR on NSR enforcement. (ES&T, 2008)

A second implication is that emission reductions due to new regulations or legal settlements within the cap and trade region may cause emission dislocations to other areas. To the extent that this dislocation affects local air quality, there could be an important to public health. This is because emissions have a relatively larger impact on the immediately surrounding region. Because cap and trade regulations only consider total emissions, local emissions can rise without check within a region that is complying with the overall emission cap. In fact, reductions in one location within the capped area can promote increases in another location because allowances are freed up and are available to be emitted in another area.

CONCLUSIONS

Overall national emissions were not found to be significantly affected by changes in the modeling input assumptions made between EPA 2.1.9 and 3.0. Changes in the modeling assumptions included fuel prices, control technology parameters, state and federal regulations and NSR litigation settlements. NSR settlements that do not include the surrender of allowances may affect emission distribution slightly but do not affect the outcome of the modeling exercise to any important degree.

However, modeling inputs strongly affect the distribution of emissions between regions. This can be seen in the radically different results of the two generations of modeling runs compared in this paper. The most important driver for these differences is the relative price paid for fuels. Input by national experts resulted in fuel price curves that changed by 40-60 percent in the span of two years.

Evaluation of the interaction between “Command and Control” and “Cap and Trade” type emissions should be made to mitigate unintended interactions between the two types of regulations.

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KEY WORDS

IPM

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