Multi-Pollutant Emission Control of Electric Power Plants

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ABSTRACT

In contrast to past regulations for power plant air pollutants, there is growing interest in a multi-pollutant perspective that would simultaneously address criteria pollutants, air toxics, and greenhouse gases. This paper addresses some of the key technical and economic questions needed to assess policy proposals, namely: What technical options are available to control each of these pollutants? What plant-level interactions must be considered in evaluating the feasibility and cost of alternative control measures? What advantages are there to multi-pollutant control strategies? The Integrated Environmental Control Model (IECM) developed for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) is used to obtain illustrated quantitative estimates of the cost and emissions impacts of interactions among technologies for multi-pollutant controls.

BACKGROUND

Historically, air pollutant emissions from U.S. power plants have been controlled on a piecemeal basis in response to new regulations for individual pollutants. Until now, particulate matter, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) have been the principal species of concern. Known as "criteria" air pollutants, emission rates of these three pollutants have been ratcheted down over the past three decades in response to increasingly stringent regulatory requirements for new and existing sources. Figure 1 shows the reductions stemming from changes in the Federal New Source Performance Standards (NSPS) for coal-fired power plants. Some new power plants currently achieve emission levels substantially below NSPS requirements.[1] In addition, many existing plants now face emission limits close to or below the NSPS values set in the 1970s.

Figure 1. Environmental Emissions from Coal-Fired Power Plants
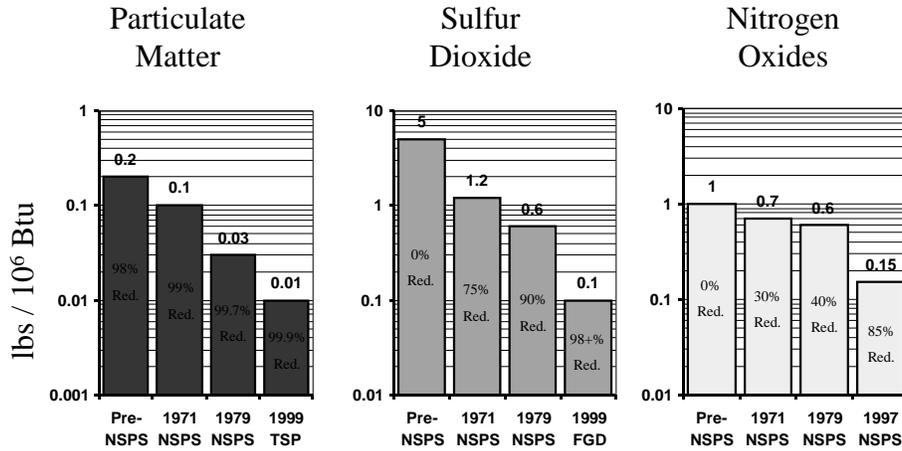
The principal drivers behind power plant emission reductions have been the federal Clean Air Act Amendments (CAAA) of 1970, 1977 and 1990. In the past decade, emissions of SO_2 from existing coal-fired plants have been reduced by nearly 9 million tons (40 percent below 1990 levels) in response to the acid rain control provisions of the 1990 Amendments. Many of these same power plants were also required to install control technology to reduce NO_x emissions to further control acid deposition. More stringent NO_x reduction requirements at the state level have been imposed more recently to help achieve air quality standards for ozone (O_3). These controls are slated to be in place by 2003.[2,3]

Looking ahead, further reductions in power plant emission are expected, not only for criteria pollutants, but also for air toxics (especially mercury) and greenhouse gases (especially carbon dioxide, CO_2). In December 2000, the U.S. Environmental Protection Agency (EPA) announced its intention to regulate mercury (Hg) emissions from coal-fired power plants under the air toxics provisions of the 1990 CAAA.[4] Mercury controls would have to be installed by 2007 according to the current timetable. EPA's new ambient air quality standards for ozone and fine particulate matter ($PM_{2.5}$), together with standards for regional haze, are expected to require further reductions of power plant SO_2 and NO_x emissions — which are precursors to all these pollutants — some time later in this decade.[5,6]

Future requirements for greenhouse gas reductions are more uncertain. Although President Bush recently took off the table any immediate action to reduce power plant CO_2 emissions, pressures to reduce such emissions still remain. There is considerable

uncertainty, however, as to the timing, methods, and magnitude of future CO_2 reductions from power plants.

PROPOSALS FOR MULTI-POLLUTANT CONTROL

Over the past several years, a number of legislative proposals have been introduced in the U.S. Congress to require power plants to simultaneously reduce emissions of SO_2, NO_x, Hg and CO_2. (Although CO_2 is not formally labeled a "pollutant" under current environmental laws, it is commonly included in references to a "four pollutant" control strategy.) Table 1 shows the emission reduction requirements proposed in two recent bills introduced in the U.S. Senate and House of Representatives, respectively. These provisions are representative of more than half a dozen policy proposals put forth in recent years. Some proposals, such as S.1949 in Table 1, would establish emission reduction requirements and allowable emission rates for individual power plants. Most policy proposals, however, such as HR 2900, would establish national emission caps on each pollutant and allow emissions trading to minimize overall cost.

Table 1. Recent Legislative Proposals for Multi-Pollutant Control

	S. 1949. Clean Power Plant and Modernization Act of 1999	**H.R. 2900. Clean Smokestacks Act of 1999**
NO_x	90% removal at each plant	Cap at 1.55 Mt/yr (75% < 1997)
SO_2	95% removal at each plant	Cap at 2.32 Mt/yr (75% < 1997)
Hg	90% below 1997 level	90% below 1997 level
CO_2	1.55 lbs/kWh (coal), 1.3 (oil), 0.9 (natural gas)	Cap at 1914 Mt/yr (1990 level)

While none of these multi-pollutant proposals have yet garnered broad Congressional support, they are nonetheless suggestive of the kinds of requirements that could be imposed on coal-fired power plants in the future. (Recall, for example, that the acid rain control program adopted in 1990 required the same level of emissions reduction stipulated in many of the earlier Congressional proposals.) Among the questions that arise in considering the feasibility and cost of a multi-pollutant control strategy are the following:

- What options are available to reduce emissions of these pollutants?

- What interactions (if any) must be considered in evaluating the feasibility and cost of multi-pollutant controls?

- What are the advantages of a multi-pollutant control strategy?

EMISSION CONTROL OPTIONS

In general, the methods available to reduce or eliminate power plant emissions include: (1) switching to a cleaner fuel containing less of the undesirable constituents; (2) installing control technology to reduce or eliminate emissions; (3) improving power generation efficiency to reduce emissions per kilowatt-hour generated; (4) switching to a power generation technology with lower or no emissions; and (5) generating less electricity by reducing demand or by reducing the load factor of "dirtier" plants.
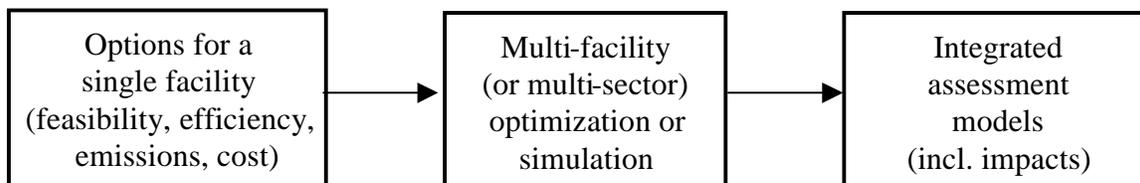
The choice of a control strategy is typically dominated by the cost of alternative options. For existing coal-fired plants, coal switching and/or the installation of control technology historically have been the preferred approaches to environmental compliance. For new plants, natural gas combined cycle systems have become the lowest cost option in most of the country, although the recent volatility in natural gas prices could affect the longer term outlook for this option. Environmentally, however, natural gas is attractive because it reduces or eliminates emissions of all pollutants of concern.

EVALUATING FEASIBILITY AND COST

Analyses of competing options for environmental control are typically carried out using computer models to simulate or optimize the electric utility response to new requirements or policy proposals. Figure 2 depicts several a hierarchy of modeling tools that are currently used for analysis. One type of model (to be elaborated in this paper) evaluates emission control options and costs at the level of a single plant or facility. This type of model is able to incorporate a fairly high level of technological detail and site-specific factors, while offering fast turnaround time and minimum data requirements. The plant-level model typically draws upon results of more detailed process-level models and data for individual plant components.

Other models are designed to analyze multiple facilities and multiple time periods. These models are more complex and data intensive. Typically they treat power plants as aggregates of representative facilities of a given type or class. While these models have less technological detail, they incorporate a wider variety of interactions such as inter-fuel substitutions, energy demand forecasts, electric power dispatching, and macroeconomic impacts. The National Energy Modeling System (NEMS) used by the U.S. Department of Energy (DOE) for its Annual Energy Outlook[7] is an example of this class of model.

Figure 2. A Hierarchy of Models for Policy Analysis

| Options for a single facility (feasibility, efficiency, emissions, cost) | → | Multi-facility (or multi-sector) optimization or simulation | → | Integrated assessment models (incl. impacts) |

The third class of models depicted in Figure 2 are integrated assessment (IA) models. These large-scale models link anthropogenic emissions to the environmental consequences and impacts of proposed policy measures. Typical applications of IA models include assessments of acid deposition, ambient ozone concentrations, and atmospheric CO_2 levels. IA models attempt to represent the complex couplings between emissions, atmospheric processes, and resulting impacts at the regional, national or global scale, for time periods ranging from decades to a century or more. The RAINS model of acidification is an example of this class of model.[8]

In principle, the different types of modeling and assessment tools depicted in Figure 2 can draw upon one another to form an overall hierarchy of analytical capabilities able to address a broad spectrum of questions. In the present paper, the emphasis is on the "bottom-up" plant-level model. This perspective is needed to develop a careful understanding of plant-level factors that influence the feasibility and cost of multi-pollutant emission control strategies. It is important that large-scale "top-down" models in turn adequately represent such factors and interactions in their more aggregated representations of power plant technologies.

THE IECM MODELING FRAMEWORK

The Integrated Environmental Control Model (IECM) developed for DOE/NETL by Carnegie Mellon University provides plant-level performance, emissions and cost estimates for a variety of environmental control options for coal-fired power plants. The model is built in a modular fashion that allows new technologies to be easily incorporated into the overall framework. A user can then configure and evaluate a particular environmental control system design. Current environmental control options include a variety of conventional and advanced systems for controlling SO_2, NO_x, particulates and mercury emissions for both new and retrofit applications. The IECM framework now is being expanded to incorporate a broader array of power generating systems and carbon management options.[9] Key features of the modeling framework are highlighted below.

Technology Performance Models

The building blocks of the IECM are a set of performance and cost models for individual technologies that can be linked together to configure a user-specified power generating system. The process performance models employ mass and energy balances to quantify all system mass flows including environmental emissions. The energy requirements of each technology also are modeled and used to calculate the net efficiency of the overall plant. Details of current models can be found in published papers and reports[10,11] and the software is publicly available for downloading.[12] Typically, each process performance model has approximately 10 to 20 key input parameters, depending upon the complexity and maturity of the technology.

Technology Cost Models

For each technology module in the IECM, associated cost models are developed for total capital cost, variable operating costs, and fixed operating costs. These elements are combined to calculate a total annualized cost based on a consistent set of user-specified

financial and lifetime assumptions. Normalized cost results, such as costs per kilowatt (or kilowatt-hour) of net capacity, and the cost per ton of pollutant removed or avoided, also are calculated. Cost models typically have about 20 to 30 parameters per technology, including all indirect cost factors and unit costs.

An important feature of the cost models is that they are explicitly coupled to the process performance models. Thus, capital costs depend on key flowsheet variables such as mass or volumetric flow rates, and important thermodynamic variables such as temperature or pressure. Annual operating and maintenance (O&M) costs also are linked to mass and energy flows derived from the process performance model.

Characterization of Uncertainties

An important feature of the IECM is the capability to rigorously characterize and analyze uncertainties. In addition to conventional deterministic (single-valued) calculations, the IECM allows any or all model input parameters and output results to be quantified probabilistically. This allows the interactive effects of uncertainties in many different parameters to be considered simultaneously.

Stochastic analysis thus provides quantitative insights about the likelihood of various outcomes, allowing users to more rigorously address questions such as:

- What is the likely cost (or cost savings) of a particular emission control strategy relative to other options? What are the potential risks such as shortfalls in performance or overruns in cost?

- Which control methods and technologies are most suitable for a given plant? Are there particular markets or applications that are likely to be most attractive for a given approach?

- Which parameters contribute most to overall uncertainty in performance and cost? What are the potential payoffs from targeted research and development to reduce key uncertainties?
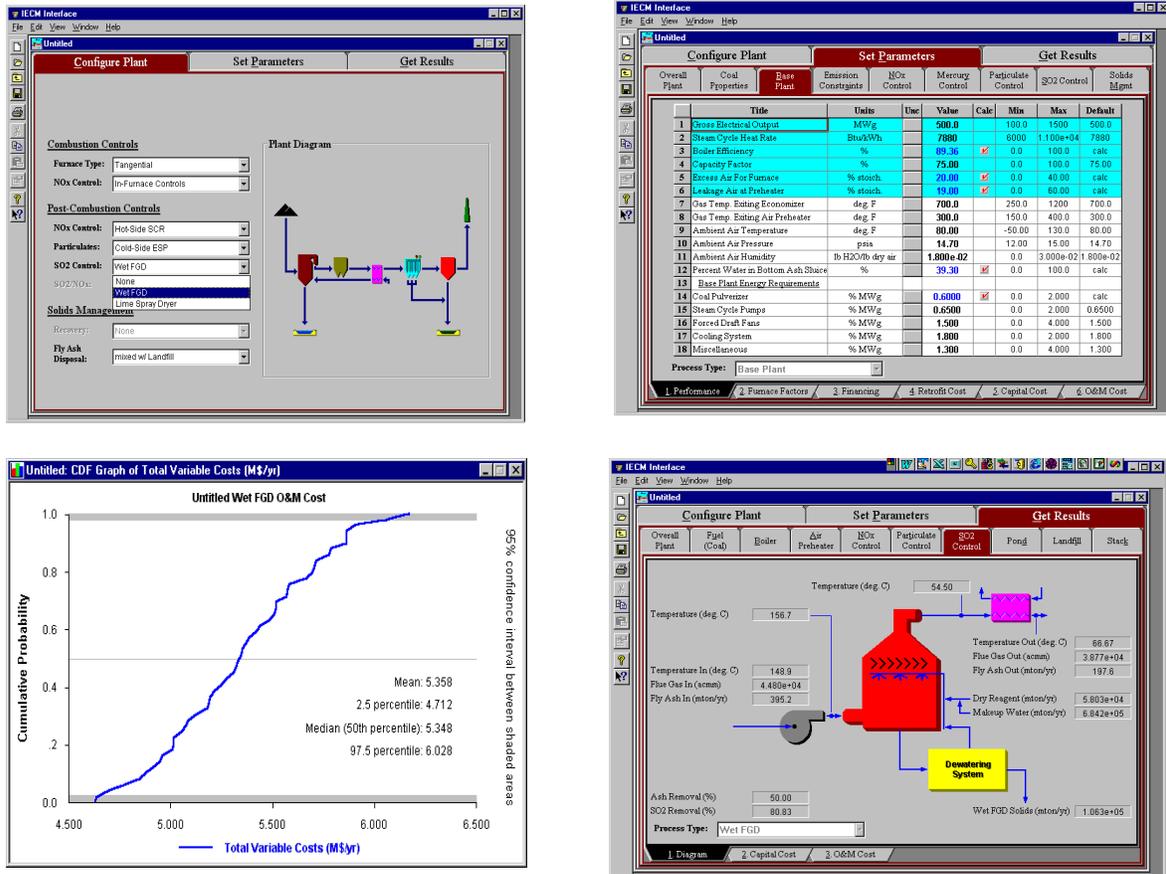
Multi-Pollutant Emissions Accounting

The IECM modeling framework accounts for emissions of criteria air pollutants (SO_2, NO_x, and particulates), major air toxics (especially mercury), CO_2 and other greenhouse gases, and all system solid wastes or byproducts. Accounting for multi-pollutant emissions is important for assessing the overall environmental benefits of an emission control technology, and for determining whether such systems inadvertently cause or aggravate other environmental problems.

User-Friendly Operation

The IECM was designed to provide sophisticated modeling capabilities with quick turn-around time (seconds per run), transparency, and ease of use. A user-friendly graphical interface provides the capability to configure an analysis, set key parameter values (and their uncertainties), and get results in either probabilistic or deterministic form. A variety

of graphical, pictorial, and tabular reports are available via the interface. Figure 3 shows several screen shots from the IECM's current graphical user interface.

Figure 3. Sample Screens from the Current IECM Graphical User Interface

MULTI-POLLUTANT INTERACTIONS

We use the IECM to explore the technological options available to reduce or eliminate emissions of criteria air pollutants, air toxics and greenhouse gases at a coal-fired power plant. Of particular interest are the interactions among technologies designed to control individual pollutants. The effects of such interactions on the costs, emissions, and efficiency of power generation are highlighted in the discussions below.

Effects of SO$_2$ Emission Controls

Coal switching and the installation of flue gas desulfurization (FGD) systems have been the principal methods used to reduce SO$_2$ emissions from coal-fired power plants. Reducing emissions by switching to a low-sulfur coal, however, can adversely affect the performance of an electrostatic precipitator (ESP), the most common method of particulate control. This is because the particulate collection efficiency is affected by the

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flue gas sulfur content. The IECM incorporates a model of flyash resistivity which is dependent upon both the chemical composition and thermodynamic properties of the flue gas and flyash to be collected. All other things being equal, lowering the flue gas sulfur content increases the flyash resistivity, lowering the overall collection efficiency. Thus, to maintain the same level of particulate emission control, a larger electrostatic precipitator is required. Table 2 shows illustrative results using the IECM. Here, the multi-pollutant effect of installing several different emissions control technologies onto a "base case" 500 MW plant burning a high-sulfur eastern coal are shown. In the first case, the fuel is switched to a low-sulfur western coal, reducing SO_2 emissions by 83 percent. However, particulate emissions now increase by 34 percent, mainly because of poorer ESP performance. Upgrading the ESP to achieve the allowable (original) emission level requires an additional capital cost of $5.6/kW in this example. Additional multi-pollutant impacts from coal switching are increases in both NO_x and mercury emissions due to the low-S coal characteristics.

Table 2. Multi-Pollutant Impacts of Emission Control Options

Primary Emission Controlled			Multi-Pollutant Interactions	
Pollutant	**Method**	**Reduction[a]**	**Pollutant**	**Effect[a]**
SO_2	Low-S coal	83%	PM	34% increase
			Hg	36% increase
			NO_x	30% increase
SO_2	Wet FGD	89%	PM	50% decrease
			Hg	70% decrease
			CO_2	2% increase
NO_x	SCR	79%	PM	27% decrease
			SO_3	170% increase
			NH_3	trace increase
NO_x +SO_2	SCR + FGD	79% NO_x + 89% SO_2	Hg	94% decrease
			PM	54% decrease
			SO_3	40% increase
			CO_2	2% increase
Hg	ACI+H_2O	90%	PM	9% increase
CO_2	MEA	87%	SO_2	99% decrease
			NO_x	20% increase
			NH_3	trace increase
			MEA	trace increase

[a]Relative to Base Case Plant: 500 MWg, ESP only (0.03 lb/MBtu), Illinois #6 coal (3.25%S), 67% capacity factor. All reductions are based on emissions per *net* kWh generated, accounting for the energy requirements of pollution controls.

Reducing SO_2 using an FGD system, the second case in Table 2, gives rise to more complex multi-pollutant interactions. Besides capturing SO_2, a conventional wet lime or limestone scrubber also removes particulate matter and air toxics. Typical removal

efficiencies vary from roughly 30 percent to 95 percent depending on the substance of concern.[13] Thus, an FGD system provides emission control benefits beyond SO_2 alone. On the other hand, FGD systems also generate a substantial amount of solid waste, although some plants eliminate this problem by reclaiming byproduct gypsum for use in wallboard manufacturing. FGD systems also generate additional emissions of CO_2 (a greenhouse gas) via the chemical reactions that capture SO_2. Finally, because FGD systems are energy intensive, emissions of all pollutants increase slightly when normalized on *net* kilowatt-hours of electricity generated. Table 2 gives a quantitative illustration of multi-pollutant impacts for the case study plant. Although an FGD system adds considerably to the total plant cost (in this case $151/kW and a 23% higher cost of electricity), there are offsetting reductions in the ESP cost (of about $6/kW for a new plant) due to multi-pollutant interactions. As discussed later, an FGD system also can reduce substantially the cost of mercury control.

Effects of NO_x Emission Controls

To date, reductions in power plant NO_x emissions have been achieved mainly through the use of low-NO_x burners and other types of combustion controls. In response to more stringent requirements recently imposed on many northeastern power plants (as part of regional ozone attainment strategies), the use of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) have become more prevalent.[3]

At some plants, the use of low-NO_x burners has been accompanied by an increase in unburned carbon caused by changes in furnace firing conditions. Most of the carbonaceous material appears in the collected flyash. Since unburned carbon represents an efficiency penalty for the overall power plant, careful design of combustion control methods is required to minimize or avoid such losses. However, there is also some evidence that mercury can be adsorbed onto unburned carbonaceous material, so that in a multi-pollutant strategy, eliminating unburned carbon altogether might not be optimal. Such tradeoffs remain to be explored.

The use of an SCR system for NO_x control leads to additional multi-pollutant interactions, as illustrated in Table 2. First, the injection of ammonia introduces a new constituent in the flue gas stream. Unreacted ammonia can adversely affect the saleability of collected flyash because of its odor and may be regarded locally as an undesired air pollutant. SCR and SNCR systems thus must be designed to achieve very low levels of ammonia slip, which may limit the level of NO_x reductions that are achievable. More subtle interactions stem from catalytic reactions within an SCR reactor. For example, SCR systems tend to oxidize some SO_2 thus increasing the level of sulfur trioxide (SO_3) in the flue gas stream. This increases the level of sulfuric acid aerosol emissions reportable under the Toxics Release Inventory.[13] On the other hand, SO_3 is also a gas conditioning agent that can improve the performance of an electrostatic precipitator. Thus, power plants with SCR systems can experience improved ESP performance, and new plants can (in principle) be designed with a slightly less expensive ESP. A plant with both SCR and wet FGD can achieve an even greater ESP cost reduction (15 percent for the reference plant in Table 2). However, the levelized cost of electricity (COE) for the plant is 30% higher than for the base case with only an ESP.

The role of SCR and FGD systems in reducing mercury emissions also has gained attention recently, as discussed below.

Effects of Mercury Emission Controls

Mercury in power plant flue gases can be captured in two ways. It can be adsorbed onto the surface of a sorbent material such as activated carbon, or it can be dissolved in an aqueous solution such as in a wet lime or limestone FGD system. Mercury control technology has not yet been installed commercially at coal-fired power plants, although some large-scale tests are currently underway. Data from smaller-scale tests indicate that mercury capture efficiency may be strongly affected by interactions with other environmental control systems.

For existing coal-fired plants with only a particulate collector such as an ESP, mercury control can be achieved by injecting activated carbon upstream of the ESP. To achieve high levels of mercury control, substantial amounts of carbon injection are required, increasing the load on the particulate collector. Thus, a larger ESP, or a second collector (e.g., a baghouse filter), is needed to achieve allowable particulate emission levels if activated carbon injection (ACI) is used for mercury control. The additional use of water injection to cool the flue gas can significantly reduce the activated carbon requirement and the associated load on the particulate collection device. Table 2 illustrates the results of one scenario modeled with the IECM. In the mercury control case, the ACI system (including humidification and waste disposal) adds $24/kW to the plant capital cost and increases the cost of electricity (COE) by 23 percent.

By contrast power plants already equipped with a wet FGD system can achieve mercury emission reductions at substantially lower costs. Case 2 in Table 2 illustrates the results for the plant using high-sulfur coal and an FGD system. Here, 70 percent of total mercury is captured by the FGD unit. The incremental cost of 90 percent mercury capture using ACI increases the COE by only 4 percent.

For plants burning eastern bituminous coals, limited data suggests that the presence of an SCR system together with a wet FGD system can eliminate altogether the need to inject activated carbon while achieving high levels of mercury control.[14] On the other hand, for plants without a wet FGD system, the addition of SCR appears to have little or no effect on mercury capture efficiency. More complete discussions of these effects, and their implications for mercury control costs, are presented elsewhere.[14] Additional research is clearly needed to better understand the complex physical and chemical factors that influence multi-pollutant control strategies involving mercury.

Effects of CO_2 Emission Controls

Options for reducing CO_2 emissions from electric power generation fall into the same general categories outlined earlier. However, recently studies by the DOE and others suggest that the most likely option would be to abandon coal-fired power generation in favor of a switch to natural gas using combined cycle systems that substantially lower the CO_2 emissions per unit of electricity produced.[15] The use of natural gas would simultaneously eliminate emissions of SO_2 and mercury, and substantially reduce

emissions of NO_x. Particulate emissions and solid wastes associated with coal-fired generation also would be eliminated under a conversion-to-gas strategy. Thus, from an environmental viewpoint, the use of natural gas for power generation has substantial multi-pollutant benefits.

The economic cost of such a strategy, however, remains in doubt. The timing and magnitude of CO_2 emission reduction requirements and the future availability of natural gas supplies are the key determinants of the cost impacts and viability of such a strategy. Unfortunately, not even the most sophisticated computer models can foretell the price of natural gas with any certainty, and the recent volatility of gas prices has focused renewed attention on the vulnerability and reliability of future gas supplies.

The use of advanced coal-based generation technology such as integrated gasification combined cycle (IGCC) systems offers another route to achieving modest CO_2 reductions through efficiency improvements. Because of its high capital cost, however, the IGCC option is not currently competitive with conventional alternatives for new power plants. The imposition of a carbon constraint could change that picture, in which case IGCC would compete with all other options (including nuclear and renewables). The use of IGCC for repowering existing coal-fired plants also would become more attractive under a CO_2 emission reduction policy.

The option of capturing CO_2 from power plant flue gases and storing it in geologic formations such as depleted oil and gas wells, depleted or unmineable coal beds, and deep saline formations, also may become feasible in the not-too-distant future.[16,17] Commercial technology already exists to separate and capture CO_2 from gas streams, but the ability to safely and reliably sequester the CO_2 in geological formations remains to be demonstrated. Substantial research efforts are underway to lower the high costs of CO_2 capture, and to develop viable methods for CO_2 storage. To the extent these efforts are successful, coal could continue to serve as a primary fuel for power generation with little or no releases of CO_2 to the atmosphere.

One potential application is the use of existing amine-based technology to capture CO_2 at existing power plants. This CO_2 control method would introduce a number of new multi-pollutant interactions. Because amine-based sorbents absorb all acid gases, not just CO_2, the level of SO_2 in the flue gas must be kept very low, typically 10 ppm or less.[18] This means that the most economical approach to CO_2 capture will be to reduce SO_2 emissions to levels substantially below those currently required for regulatory compliance. Emissions of NO_2 also would be reduced slightly, as would emissions of particulates and HCl. On the other hand, the amine chemistry would generate additional emissions of ammonia, trace emissions of sorbent, and additional solid wastes in the form of reclaimer bottoms from the recovery of spent sorbent. Another drawback of this technology, is its high auxiliary energy requirement, amounting to roughly 20 to 25 percent of gross power plant output for current system designs. Because of this substantial loss of plant capacity, the pollutant emissions actually avoided are smaller than the amounts that are captured. In the case of NO_x, emissions per net kilowatt-hour actually increase. The last case in Table 2 shows illustrative results for one case study based on current amine scrubbing using MEA as the sorbent. At the present time the cost of this option is prohibitive, since

it would nearly double the cost of power generation. As noted earlier, a broad array of advanced CO_2 capture/storage options are under development for fossil fuel power systems.[19] Future versions of the IECM will incorporate many of these technologies as additional options for multi-pollutant controls.

CONCLUSION

This paper has illustrated the highly interactive nature of environmental control systems for SO_2, NO_x, mercury and CO_2. Because of these interactions, control strategies that consider all of these substances simultaneously will be more cost-effective than a piecemeal solution that considers them individually. This is especially true if future reductions in CO_2 emissions are envisioned in addition to reductions in criteria air pollutants and air toxics.

For the moment, however, U.S. policy has put off dealing with power plant CO_2 emissions, leaving a three-pollutant strategy as the most likely scenario for the near term. Here too, however, multi-pollutant interactions will affect the cost of environmental compliance, as illustrated by the examples in Table 2. Future case studies will investigate in more detail the design of optimal control strategies for different power plant configurations and fuels. The results of such studies will better define the benefits of a multi-pollutant approach, and the options that must be considered in higher-level models used for policy assessments. Such interaction between "bottom up" and "top down" models is likely to produce the most credible and useful insights as to the costs and environmental benefits of multi-pollutant strategies for controlling criteria pollutants, air toxics, and greenhouse gases.

ACKNOWLEDGMENTS

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