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Project Summary

Control of Criteria and Non-Criteria Pollutants from Coal/Liquid Mixture Combustion

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As the availability and cost of oil has become uncertain in recent years, the need for the United States to reduce its dependence on oil has prompted significant efforts by government and industry in finding alternate fuel sources. This posture has been strengthened by the Powerplant and Industrial Fuel Use Act of 1978 that prohibits the use of gas and oil in new boilers without special exemption. The Department of Energy (DOE) has taken an active role in developing two such alternate fuel technologies: coal/oil mixture (COM) and coal/liquid mixture (CLM) combustion.

Recognizing that environmental considerations must be addressed in any evaluation of fuel conversion to COM or CLM, DOE and the EPA's Industrial Environmental Research Laboratory-RTP (IERL-RTP) contracted with Radian Corporation to identify and assess the effectiveness of currently available methods of controlling the release of criteria and non-criteria (trace elements) pollutants from the combustion of COMs and CLMs. This report gives results of this assessment and compares the costs and effectiveness of various control technologies found to be applicable to emissions from boilers firing CLM. A previous report (EPA-600/7-83-040) gave results of a similar assessment of boilers firing COM.

To date, the combustion of coal/water mixtures (CWMs) has received the most attention, and is thus the focus of this report. Coal/alcohol mixtures (CAMs) represent another fuel alternative which could potentially replace oil or natural gas in existing boilers, although there is currently limited activity in the development of CAMs as fuels. This report briefly summarizes activities and advances made in the development of CAMs as fuels.

Emissions from CLM combustion were characterized using data from various tests. In the absence of data for CLM-firing, the discussion focuses on data from coal- and COM-firing, with corollaries to CLM combustion. The pollutants examined most closely were particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NO_x). Trace element emissions and emissions of polynuclear organic material (POM) were also examined. Conventional emission control techniques were determined to be the most effective in reducing emissions from CWM combustion. Cleaned coal must be used in the preparation of CWMs, and it has been determined that coal cleaning can also significantly reduce particulate matter and SO_2 emissions from CWM combustion.

Emission rates and associated costs for emissions control of particulate matter and SO_2 were assessed for four CWM compositions and various boiler sizes. Physical coal cleaning was considered for pre-combustion control of particulate matter and SO_2.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Coal/water mixtures (CWMs) have been combusted successfully in Department of Energy (DOE) research in small, test combustion units, and full-scale testing is planned for the near future. Coal/alcohol mixtures (CAMs) are not yet well-developed as a slurry fuel; furthermore, they are still more expensive than CWMs or coal/oil mixtures (COMs).

As CLM combustion technology becomes more widespread, DOE and the Environmental Protection Agency (EPA) recognize that certain environmental considerations will have to be addressed in order to expand the use of CLM in an environmentally acceptable way. Specifically, it will be necessary to determine the potential emissions from sources burning CLMs and evaluate, assess, and compare the effectiveness of control technologies in limiting criteria and non-criteria pollutant emissions. Radian Corporation has been under contract to EPA and DOE to conduct a study aimed at identifying and assessing the effectiveness of currently available methods of controlling the release of criteria and non-criteria (trace elements) pollutants from the combustion of CLMs.

The report generated from this study contains several chapters that focus on the various considerations and assessments necessary in making a conversion from oil or gas to CLM. This report focuses primarily on CWM combustion in existing oil- or gas-fired boilers. The report also briefly discusses CAMs and their potential advantages and disadvantages. Chapter 2 presents some of the technical and economic factors that determine the suitability of CWM as a fuel and identifies boilers that might be candidates for CWM conversion.

Chapter 3 discusses the emissions that have been measured to date on combustion units burning CWMs. The criteria pollutant emissions that are discussed are particulate matter, sulfur dioxide (SO_2), and oxides of nitrogen NO_x). Non-criteria pollutant emissions discussed are the selected trace elements, arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), nickel (Ni), selenium (Se), vanadium (V), and mercury (Hg), as well as polynuclear organic matter (POM) emissions. Chapter 3 also briefly discusses control technologies that are applicable to boilers that could be converted to burn CWMs. Several of these control techniques, as discussed later in this Summary, were the subject of further technical and economic study presented in the remainder of the report.

Chapter 4 presents the environmental impacts of the selected control technologies, including the primary pollutant control capability and any secondary environmental impacts. The potential for multipollutant control is also discussed. Chapter 5 addresses the cost impacts of the technologies discussed in Chapter 4 in terms of capital costs, annual operation and maintenance (O&M) costs, annualized costs, and cost effectiveness. Multipollutant controls, add-on controls, and low-sulfur CWMs are also compared in this chapter.

Use of CWMs in Existing Boilers

CWMs, also referred to as coal/water slurries, consist of 65-75 weight percent coal in water with minor percentages of additives. Bituminous coals are most frequently used in the preparation of CWMs, but some lignite and subbituminous coals may also be used. Because coals vary widely in ash and sulfur content, only cleaned coals or low-sulfur, low-ash coals are used in the preparation of CWMs to ensure a more consistent fuel quality. Due to the economics of CWM preparation facilities, it is most likely that these mixtures will be prepared in centralized off-site facilities rather than at the boiler site.

The suitability of converting a boiler currently firing oil or gas to CWM depends on several technical and economic factors. The likelihood of a specific boiler's being a candidate for CWM will depend on the age of the boiler (remaining useful life), boiler design, size and capacity factor, geographical location (proximity to CWM fuel supply), site-specific boiler modifications required, existing emission control equipment, if any, and emission controls required by applicable environmental regulations.

Technical Considerations

Three basic factors must be evaluated in determining the technical suitability of converting existing oil- or gas-fired boilers to CWM: CWM fuel properties, CWM combustion characteristics, and boiler modifications required to accommodate CWM-firing.

Other than combustion characteristics, the most important CWM fuel properties to be considered are viscosity, stability and abrasiveness. Viscosities of CWMs range from about 450 to 2,000 cP, or from a paint-like consistency to that of a thick gel. The desired high solids loading and decreased viscosity can be brought about by utilizing bimodal particle size distributions and/or by the use of additives in the preparation of CWMs. Generally, conventional pumping methods are adequate to handle CWMs, although there may be potential erosion problems. Chemical stabilizing additives, typically emulsifying agents, gelling agents, or surfactants, have been developed to improve COM stability by keeping the coal particles suspended in the oil. The increased abrasiveness of CWM relative to oil can potentially cause erosion in pipe bends, pumps, valves, and burners. These potential problems can be minimized by selecting proper materials, reducing fuel velocities, and using more finely ground coal.

The boiler modifications required in converting from oil or gas to CWM are site-specific, and depend on such boiler design factors as tube spacing, burner design, furnace size, and bottom ash removal capability. Boilers originally designed for oil- or gas-firing commonly have narrower tube spacings than boilers originally designed for coal-firing, making coal-fired boilers more ideally suited, in that respect, for conversion to CWM combustion. In converting to CWM, the potential exists for ash deposition and slagging (if the furnace temperature is not maintained below the ash fusion temperature). Bridging of molten ash between the tubes leads to impaired heat transfer and, possibly, boiler derating. Soot blowers would generally be required to prevent these problems; although some existing oil-fired boilers have soot blowers, additional soot blowing capacity may be needed to accommodate CWM combustion. Since most CWM combustion studies have found air or steam atomization preferrable to mechanical atomization burners may have to be modified or, in some cases, replaced. To facilitate switching from CWM- to oil-firing with maximum flexibility, careful consideration of burner design or modification is necessary. Combustion of CWM requires a larger combustion space relative to oil to allow for the longer residence time needed for complete combustion of the coal particles. Refitting for CWM combustion will require provisions for a bottom ash handling facility in most cases, since units designed for oil- and gas-firing do not often have bottom ash removal capability.

In addition to modifications made directly to the boiler, other changes to the facility may be required in converting to CWM. These changes are primarily associated with the fuel handling system (including pumps, piping, valves, and flow measurement devices). Storage tanks for CWM received from a centralized off-site preparation plant may have to be modified to include agitators and temperature controls. New storage equipment will be required if dual fuel capability (CWM and oil) is desired.

Economic Considerations

Several economic factors will also impact the desirability of converting to CWM firing. Paramount among these considerations of the use of CWM in general is the cost of coal relative to that of oil. Currently, widespread use of CWM is limited by the low price of oil.

The economic considerations of converting a particular boiler to CWM firing may be somewhat complex, particularly for utility applications. However, the economic impacts of the following factors are important in every case: capital availability; boiler modifications required; difference between oil (or gas) and coal prices and the predicted rates of escalation of the fuel costs; security of oil or gas supply; availability, composition, and price of CWM; boiler size and capacity factor; remaining useful life of the boiler; and emission controls required.

The economics of conversion are also affected by the composition of the CWM (percent coal, sulfur content, and ash content), the CWM fuel cost, and the source of the CWM (on-site or off-site centralized preparation plant). CWM fuel cost is determined primarily by the cost of coal, although coal cleaning costs and CWM preparation costs also impact fuel cost.

CWM Emissions

Most often, when an existing oil-fired boiler is to be converted to CWM combustion, the uncontrolled emissions of particulate matter (PM) and nitrogen oxides (NO_x) will be greater for CWM-firing than for oil-firng. The increased emissions result from the contribution of coal ash and nitrogen to the combustion emissions. Emissions of SO_2 from CWM combustion may be less than or greater than oil-only SO_2 emissions, depending on the relative sulfur contents of the CWM and the oil. Trace elements emissions (except Ni and V) from CWM combustion may also be greater than those for oil-only firing.

PM Emissions

Measured emissions of PM fly ash from boilers firing CWM are a function of the percentage of coal in the CWM, the ash content of the coal used, and, to some degree, the amount of ash deposition in the boiler. Although test data on small test boilers suggest that most of the CWM ash (75 to 95 percent) is emitted as fly ash, some combustion tests on coal slurries have shown significantly lower fly ash emissions. Ash deposition in the boiler may cause the reduced measured PM emissions.

SO_2 Emissions

Emissions of SO_2 from CWM combustion are a direct function of the fuel sulfur content. The CWM sulfur content is in turn determined by the sulfur content of the coal used to make the CWM and the percentage of coal present in the CWM. At least 95 percent of the fuel sulfur is typically emitted as SO_2. But CWMs made with coal that has highly alkaline ash may emit slightly less than 95 percent of the fuel sulfur since the alkaline ash retains some of the fuel sulfur.

NO_x Emissions

Emissions of NO_x from boilers firing CWM are more difficult to quantify for all potential applications than are SO_2 and PM emissions. For any boiler NO_x emissions can vary not only with CWM fuel composition, but also with the amount of combustion air (excess air) and, in some cases, with boiler load. Properties of the CWM fuel that influence NO_x emissions are the nitrogen content of the coal used to make the CWM and the percent coal in the CWM. For a given fuel composition, NO_x emissions can vary significantly from boiler to boiler due to differences in burner and furnace design and the use of combustion air preheat. Although limited test data are available for NO_x emissions from CWM-firing, they indicate that emissions from CWM combustion should follow the same trends as those noted for the parent coal.

Trace Element Emissions

Trace elements in the CWM fuel exit the boiler either with the bottom ash or with the flue gas, if ash deposition in the boiler is not significant. Most of the trace elements emitted with the flue gas are associated with the fly ash, though some may remain in the vapor phase.

The amount of trace elements emitted from a particular boiler depends on: combustion temperature, fuel feed mechanism, characteristics of the flue gas, and CWM properties (trace element concentration).

The combustion temperature determines the extent to which specific trace elements are volatilized and thus the extent to which they may be emitted with the fly ash or flue gas. The fuel feed mechanism influences the partitioning of non-combustible trace elements between the bottom ash and the fly ash. The temperature of the flue gas affects the relative amounts of volatile trace elements which are emitted condensed on the fly ash particles compared to being emitted as a vapor.

Data on three coals show that coal has higher concentrations of As, Be, Cr, Hg, and Se than does oil. Residual oil has higher concentrations of Cd, Ni, and V. Thus, combustion of CWMs would likely result in higher emissions of As, Be, Cr, Hg, and Se, but lower emissions of Cd, Ni, and V, than would the combustion of oil alone.

Polynuclear Organic Material (POM)

The amount of POM emitted from any combustion source is dependent on the formation and the transformation mechanisms of the POM. POM is formed in the combustion zone either by the breakdown of larger molecules or by the building up of smaller ones. Evidence is available to indicate that POM forms in the vapor phase and later condenses on flue gas particulate matter. POM formation is related to combustion efficiency, and POM transformations are related to boiler and downstream flue gas temperatures. POM emissions from CWM combustion were not quantified in the recent studies. However, when properly fired, oil-only combustion has been shown to contribute almost no POM emissions to the environment while coal-only combustion produces POM emissions in unpredictable patterns.

Applicable Control Technologies

Pre-combustion Techniques for PM/SO_2: Physical Coal Cleaning

Physical coal cleaning is a pre-combustion control technique employed by coal/CWM producers to reduce the ash and sulfur content of coals used to prepare CWMs, and consequently reduce the PM and SO_2 emissions resulting from CWM combustion. It is expected that physical coal cleaning will be applied to all coals used in CWMs.

Physical coal cleaning can be defined generally as the separation of waste or unwanted "refuse" materials from coal by techniques based on differences in the physical properties of coal and refuse. Each coal cleaning facility is unique in its treatment of coal. Each cleaning process depends on the characteristics of the coal to be treated and the desired specifications for the cleaned coal. The sulfur removal efficiencies of physical coal cleaning processess range from about 13 percent for simple crushing and screening separation processes to about 70 percent for the most intensive cleaning processes. The sulfur removed by these processes is pyritic sulfur. The organic sulfur can only be removed by chemical modification of the coal structure. Thus, the amount of sulfur removal possible by physical coal cleaning is limited by the presence of organic sulfur. Similarly, ash removal capabilities range from about 10 to 75 percent.

It is unlikely that physical coal cleaning alone will reduce ash content to levels such that no post-combustion PM controls are required to meet air pollution regulations. In many cases, however, physical coal cleaning can reduce the sulfur content of the coal to a level such that no additional controls for SO_2 emissions are required. Even if physical coal cleaning alone cannot achieve adequate PM and SO_2 control, it can substantially reduce the amount of costly post-combustion control required. It also reduces the variability of the CWM composition, permitting tighter boiler and control design specifications.

One disadvantage of physical coal cleaning is that, although it reduces the quantity of fly ash/bottom ash and wet sludge generated at the boiler site, it has a net effect of increasing the amount of solid waste generated. In any cleaning process, some valuable combustible matter is lost as refuse, along with undesired inorganic materials. The amount of valuable coal lost as refuse ranges from about 5 to 50 percent, depending on the cleaning process and coal composition. Liquid waste impacts are also associated with physical coal cleaning processes; some facilities are minimizing liquid waste disposal requirements by recycling process water. Physical coal cleaning facilities are subject to EPA standards for air (fugitive emissions) and water quality, and MSHA/OSHA regulations for refuse disposal.

Combustion Modifications for NO_x Reduction

Combustion modification techniques for NO_x control include: low excess air (LEA) operation, staged combustion, flue gas recirculation (FGR), and low-NO_x burners. Limited data are available on the effectiveness of these combustion modification techniques in reducing NO_x emissions from CWM combustion. However, NO_x emissions from CWM combustion are expected to be similar to those from combustion of moist coal.

Low-NO_x burners are the most effective of the candidate NO_x control technologies examined in this study. Low-NO_x burner designs typically incorporate LEA, staged combustion, and/or internal FGR. Low-NO_x burners available for pulverized coal service can potentially reduce uncontrolled NO_x emissions by 65 to 90 percent. Staged combustion is a relatively effective NO_x control technology. The effectiveness of staged combustion in reducing NO_x emissions results from the formation of localized fuel-rich conditions in the primary combustion zone which minimize formation of both thermal and fuel NO_x. Staged combustion has been shown to achieve 40 to 50 percent reductions in NO_x emissions when applied to coal units. Operation at low excess air (LEA) levels is primarily effective in reducing thermal NO_x. LEA is generally incorporated as a design and operating feature in new boilers since it increases boiler efficiency and thus reduces fuel consumption. FGR is most effective in reducing thermal NO_x and is therefore not a very effective NO_x control technique for coal firing due to the high fuel nitrogen content of coal relative to other fuels. FGR will likely be ineffective for CWM firing as well.

Post-Combustion Control Techniques for PM

The emission reduction capabilities of two PM control technologies were examined in this study: electrostatic precipitators (ESPs), and fabric filters.

High particulate matter control efficiencies (98 percent or greater) have been widely demonstrated with ESPs and fabric filters. In general, these technologies can reduce fly ash emissions to 43 ng/J (0.1 lb/10^6 Btu), and in most cases to 21.5 ng/J (0.05 lb/10^6 Btu) or less. Fabric filters, generally more effective than ESPs, are not as sensitive to changes in fly ash resistivity, particle size distribution, or inlet grain loading.

Post-Combustion Control Techniques for PM/SO_2

Two post-combustion control techniques for combined PM/SO_2 removal evaluated in this study are: wet flue gas desulfurization (FGD), and spray drying FGD. These control technologies are used primarily for SO_2 control, but also achieve moderate to substantial reductions in PM emissions.

Wet FGD systems can achieve 90 percent removal of SO_2 or greater if they are designed and maintained properly. Two types of dry FGD systems appear to be promising for CWM applications: spray drying FGD and dry injection of sodium-based compounds. Although these systems are not as widely demonstrated as wet FGD systems, SO_2 removal efficiencies of up to 90 percent have been reported for coal-fired boilers.

Wet FGD systems are quite suitable for combined SO_2 and PM removal. Combined SO_2/PM control with this system favors venturi scrubbers, possibly preceded by a mechanical collector. Substantial combined SO_2/PM control is also achievable with dry scrubbing systems; e.g., spray drying (since they include a fabric filter or an ESP) and dry injection of sodium-based alkali compounds into a fabric filter. The disposal of highly soluble sodium-based wastes from dry injection may present more serious solid waste disposal problems than the disposal of calcium-based wastes from spray drying or wet FGD systems.

Post-Combustion Techniques for NO_x Control

Post-combustion control techniques for NO_x include ammonia injection (e.g., Exxon's "thermal De-NO_x") and flue gas treatment (FGT) techniques. These control techniques have not been applied widely to sources in the U.S. since existing emission limits can be met by fuel switching or by combustion modification. NO_x FGT is, however, well developed in Japan where NO_x emission limits are more stringent.

NO_x FGT processes can be classified as either dry or wet. The major wet FGT processes include absorption-reduction, absorption-oxidation, and oxidation-absorption; the major dry FGT processes are selective catalytic reduction (SCR) and selective non-catalytic reduction with ammonia (or thermal De-NO_x, as developed by Exxon). NO_x emission reductions of up to 90 percent may be achievable with these FGT processes.

Trace Element Control Technologies

The technologies that achieve the greatest degree of fine particulate control are the most efficient for trace element collection, since many of the trace elements tend to be enriched on the smaller fly ash particles. Thus, fabric filters and ESPs achieve the greatest degree of trace element control. In addition, physical coal cleaning can reduce emissions by reducing trace element concentrations in the fuel prior to combustion.

Cost Impact of Control Technologies

The cost impacts of various PM, SO_2, and NO_x control technologies for boilers firing CWM were evaluated in terms of (1) capital costs, (2) annual operating and maintenance (O&M) costs, (3) annualized costs, and (4) cost effectiveness. The impacts of various PM and SO_2 control technologies were evaluated for three CWM boiler sizes and four CWM fuels. The boiler sizes examined were: 8.8 MW (30×10^6 Btu/hr), 73 MW (250×10^6 Btu/hr), and 205 MW (700×10^6 Btu/hr). The CWM fuels for which control technology costs were calculated were selected from typical cleaned coal. Uncontrolled SO_2 and PM emission rates were calculated assuming that (1) all of the fuel sulfur is emitted as SO_2, and (2) 80 percent of the CWM ash is emitted as fly ash. Each CWM fuel was assumed to be a 70:30 mixture of coal and water. The costs of PM and SO_2 control technologies presented in the report are based primarily on the technology costs used in the EPA's development of Industrial Boiler New Source Performance Standards (NSPS).

Comparison of FGD System Costs

The costs of dual alkali, spray drying, and dry injection FGD systems are compared in Figure 1 as a function of boiler size for units firing various CWM fuels. The costs are based on a 70 percent SO_2 removal efficiency and a 60 percent annual oapacity factor. The relative costs of the three FGD systems for specific applications may be altered due to site-to site variations in SO_2 removal, boiler capacity, reagent costs, or availability of existing equipment to reduce retrofit costs.

Dry injection FGD has the lowest capital costs up to a boiler size of about 100×10^6 Btu/hr. However, wet FGD has the lowest capital cost of the three systems for boilers larger than this size. The result is due primarily to the increased particulate matter collection associated with the use of a fabric filter in the spray dryer and dry injection systems. The lower PM emission control levels achievable with fabric filters, relative to a wet FGD system used for combined SO_2/PM removal, result in higher waste disposal costs. An ESP would likely be required upstream of the wet FGD to achieve the same PM emission level.

In comparing the annualized costs for three FGD systems, wet FGD had the lowest annualized cost for boilers above about 100×10^6 Btu/hr. Below 100×10^6 Btu/hr, dry injection is the least expensive alternative, but its costs increase rapidly as a function of boiler size and it is the most costly alternative at the larger boiler sizes.

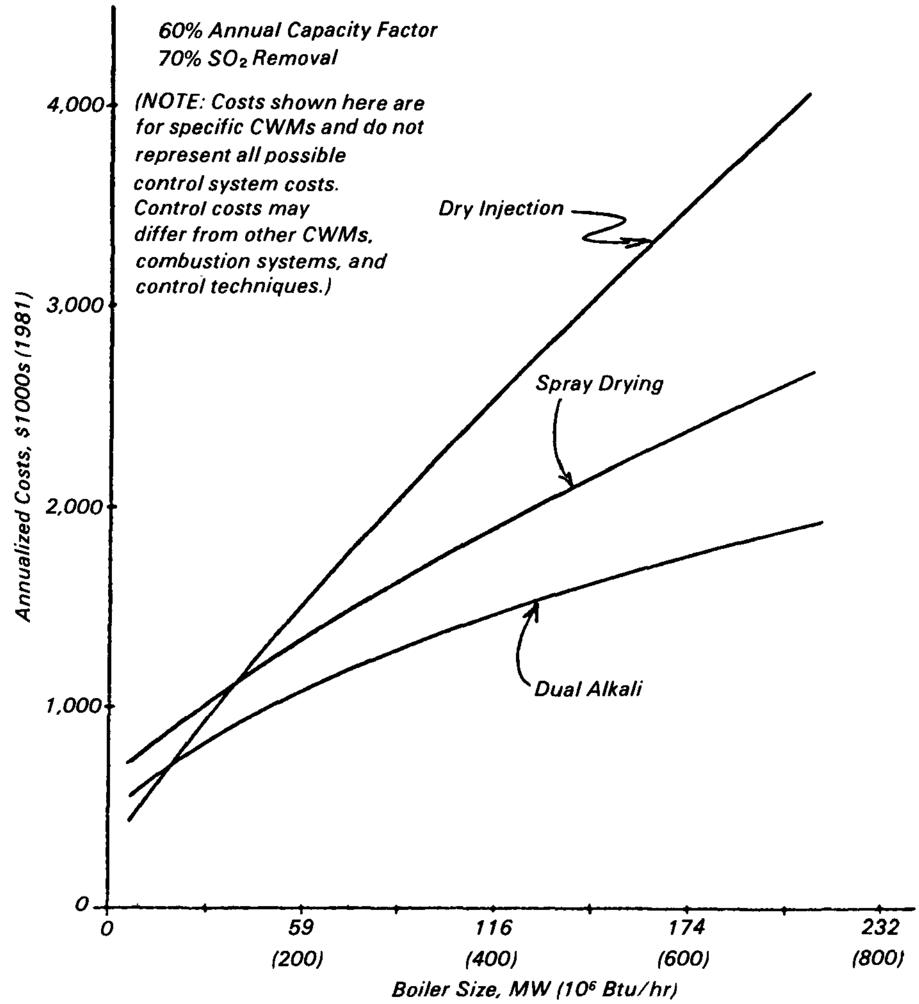

Figure 1. *Annualized costs of three FGD systems applied to boilers firing a high ash, high sulfur CWM.*

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The complete report, entitled "Control of Criteria and Non-Criteria Pollutants from Coal/Liquid Mixture Combustion," (Order No. PB 84-137 231; Cost: $20.50, subject to change) will be available only from:

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