Achieving 40 CFR Part 60 Subpart C_b CO Emission Requirement On Large RDF-Fired Municipal Waste Combustors

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INTRODUCTION

Carbon Monoxide (CO) is a colorless and odorless gas that is created when carbon based fuels are incompletely combusted. Some level of CO is produced in all practical carbon fuel combustion operations. Exposure to concentrations of CO above the permissible limit has been determined by the scientific community to be harmful to the general public. Congressional passage of the 1990 Clean Air Act required the U.S. Environmental Protection Agency (EPA) to establish concentration limits for CO as well as other products of the combustion process for affected facilities. As a result, the EPA recently promulgated 40 CFR Part 60, Subpart C_b for existing Municipal Waste Combustors (MWC). Included in these new requirements will be a CO emission concentration limit.

The refuse derived fuel (RDF) fired plant is one category of municipal waste combustor (MWC) that will be subjected to the new requirements. RDF is produced when municipal solid waste is processed to obtain a smaller and more consistent fuel particle size. RDF can be combusted to release energy for steam and/or electrical production. RDF is usually combusted by feeding it onto a traveling grate although other means have been developed, including co-firing with other fuels and fluidized bed combustion. RDF-fired unit capacity ratings are determined based on tonnage of fuel combusted per day (tons/day). The EPA established the new emission requirements based on this capacity rating. Large RDF facilities (more than 250 tons/day) will be limited to a CO concentration of 200 ppmdv @ 7% O_2. Although a recent court ruling has delayed the execution of the new requirement, the final CO concentration limit for large RDF-fired "units" is expected to remain unchanged.

Eight large RDF plants were surveyed to characterize their ability (or inability) to meet the newly promulgated requirement for CO. The reported range of typical CO emission concentrations was from 50 to 400 ppmdv @ 7% O_2. Some units will not have difficulties meeting the new CO emission concentration limit and some will have to consider operational changes and possible equipment modifications to meet the new requirement. This paper attempts to define what equipment and operational characteristics allow for the performance differences observed and also identifies techniques that can be implemented to help compliance efforts.

RDF PLANT BACKGROUND

The history of the RDF-fired waste-to-energy (WTE) plant is relatively short in comparison to other forms of combustion technology such as coal, oil, gas, and wood firing. The first applications used RDF as a supplementary fuel for conventional electric utility boilers. RDF was usually suspension-fired in combination with pulverized coal or atomized oil or gas. By the mid 1970s, new plants were being designed primarily to burn RDF. The designs were conventional stoker grate arrangements.

The first RDF facility designs were based on the proven technology of wood firing. It was believed at that time that the combustion characteristics of wood were similar to RDF. Fuel feed systems and boiler design both relied heavily on wood fired designs. These wood fired based designs incurred various problems leading boiler manufacturers and equipment designers to make significant improvements in the combustion process of RDF on stoker grates over the next ten years.

Today there are approximately eleven large waste-to-energy plants operating twenty-eight boilers on RDF. Four boiler manufacturers dominate the landscape by providing the majority of boilers for these large RDF applications, they include; ABB-CE (12 boilers), Babcock and Wilcox (7 boilers), Riley Stoker (5 boilers), and Zurn Industries (4 boilers). Each of these manufacturers have their own design signature that encourage or inhibit compliance with the new regulations.

Due to implementation of more stringent 40 CFR Part 60 Subpart C_b emission requirements for existing large RDF-fired facilities, operators must consider their impact and possible retrofit options. Modifications may include acid gas scrubbers for hydrogen chloride (HCl) and sulfur dioxide (SO_2) control, fabric filter baghouses for particulate control, and selective non-catalytic reduction systems for nitrogen oxide (NO_x) control.

FACILITY DESIGN CONSIDERATIONS

The investigation of various CO emission levels was based on the "three T's of combustion", time, temperature, and turbulence. The majority of combustion takes place prior to the furnace exit. The design of the fuel feed system and furnace are two areas of system design that directly affect the three T's of combustion and determine how complete the combustion of the RDF will be. The fuel feed system must distribute the fuel evenly on the grate. This insures that a constant undergrate air pressure will deliver the air where it is needed. The geometry of the furnace and the overfire air (OFA) ports provide the turbulence necessary for good combustion. The grate area and furnace volume determine the residence time and temperature of the gas particle as it travels through the furnace.

Fuel Feed System

The typical fuel feeding system injects the fuel in the front of the boiler and tosses it towards the rear. The objective of the system is to get the best fuel distribution front-to-back and side-to-side on the grate. Typically, three to eight individual feeders are used. Some feeders have the ability to vary the transport air pressure to improve front to back distribution. These feeder types generally provide a more even bed depth and consequently better mixing.

Many types of conveyors and system designs are used to divide and consistently convey the RDF to the feeder. Two systems commonly found are shown in Figures 1 and 2. The largest contribution the conveying system can make to controlling CO concentration emissions is to not plug. A fuel system plug often results in high CO spikes while the plug is being cleaned. However, considering that the CO emission levels are based on a 24 hour average, the conveying system does not make or break a units ability to meet the limit.

Boiler Design

The furnace is the envelope in which the majority of combustion takes place. Fuel and air are introduced on the grate which provides the floor of the "box". The size (or volume) of the box determines how much time gas particles will spend before exiting. The grate size and speed determines how much time the fuel will spend in the furnace and the bed depth required to meet steam demand. Overfire air provides the oxygen and turbulence to complete the combustion process started on the grate.

One factor considered by boiler designers is the amount of energy (Btu/hr) released per cubic foot (ft^3) of volume. This factor is termed " furnace liberation rate" and is expressed in Btu/hr/ft^3. Table 1 depicts liberation rates for the RDF facilities surveyed. This number varies significantly for the identified units. The magnitude of this number is not significantly correlated to the CO level as can be seen by the accompanying graph of Typical CO vs. Liberation Rate, Figure 3.

A more important indicator of CO emission concentration controllability is the physical geometry of the furnace. The two lowest typical CO levels were reported by facilities with Babcock and Wilcox's CCZ™ design furnaces. This furnace design, shown in Figure 4, includes two opposing noses in the lower portion of the furnace. The significance of this furnace design is not related to furnace size, but to design features which promote better mixing of the fuel and available combustion air. In contrast, competing furnace designs do not encourage turbulence above the firing grate, mainly due to the lack of furnace constriction created by multiple noses.

Another design criteria used by boiler design engineers is grate heat release rate. This factor is expressed in Btus/hr/ft^2 and is simply the fuel heat input divided by the grate area. For a desired grate heat release rate and known fuel input, the grate dimensions are set. The grate heat release rate is fairly consistent for the units surveyed as depicted in Table 2 and its accompanying graph, Figure 5. Again, little correlation was observed between CO levels and grate heat release rate. It is important to note that grate size and speed will mandate the bed depth on the grate for a given firing rate. From this data, it can be observed that there is consensus that a bed depth of 6 - 12 inches results in good undergrate air distribution and allows for burnout of the fuel on the grate, provided the fuel is evenly distributed front-to-back and side-to-side.

Overfire Air System

The goal of the overfire air (OFA) system is to promote mixing of fuel and combustion air to complete the conversion of carbon to carbon dioxide (CO_2) without adding substantially to the undergrate air (UGA) provided for primary firing of the fuel on the grate. Boiler suppliers have taken very different approaches and made significant changes to these systems during the design evolution. The conventional front and rear wall, multi-level ports were the starting point for all boilers. As Babcock and Wilcox developed the CCZ™ furnace for RDF firing, the main overfire air ports were located in the bottom nose. B&W also increased the diameter of the ports as their design evolved. This furnace configuration results in the lowest CO levels reported by the RDF plant operators surveyed. The design evolution of the ABB-CE boilers went to a proven technology implemented on CE utility boilers, tangential overfire air nozzles. This configuration is shown in Figure 6. While this technology has proven itself successful in many applications on different fuels, operators of ABB-CE RDF-fired boilers have chosen to return to conventional front and rear wall OFA nozzles, for reasons other than CO control. Other boiler designs are using OFA ports located at various elevations on the front and rear walls. Optimization programs have shown some success controlling CO with the conventional arrangement of OFA ports. To achieve this, operators must carefully set up a matrix of various OFA pressures and OFA/UGA splits while recording CO emissions. The settings can be optimized for the boiler load and fuel conditions at the time of setting. Unfortunately, these may not be the optimum settings for all conditions.

OPERATIONAL CONTROL MEASURES

Operational techniques can be employed by plant operations staff to help mitigate excess CO emissions resulting from combustion incompleteness. Measures such as controlling the fuel distribution and bed depth, steady steam load control, overfire air location and header pressure adjustment, and firing of auxiliary fuels can be implemented to reduce the average CO concentration measured and reported by continuous emissions monitoring systems (CEMS). Several facilities surveyed use these techniques, independently or in combination to help them comply with the existing and new CO emission concentration limits.

In general, these techniques can be categorized into two types; pre-combustion techniques which attempt to create optimum combustion so that generation of CO is limited, and post-combustion techniques which attempt to reburn the CO released from the grate before it exits the furnace.

Maintaining an even distribution of fuel on the grate is critical to controlling CO emission concentrations. Improperly delivered fuel to the grate can result in piles of fuel which create a reducing environment at the ignition point. Additionally, undergrate combustion air bypasses piled grate fuel due to the induced pressure drop created and compounds the problem, thus poor combustion and elevated CO levels. The causes for uneven fuel distribution include the design of the fuel delivery system, as discussed above, and instability of the fuel demand signal from the boiler controls.

The ideal conditions for CO control include a constant fuel feed rate and air flow. This is of course impossible due to variability of the fuel characteristics and changes in boiler demand. Fuel characteristics cannot be controlled by the plant operator, but steps can be taken to reduce changes in the boiler demand. The control system should be configured so that steam header pressure controls the fuel feed rate. Other control schemes may be currently utilized by operators that are counter-productive to CO control. For instance, programs which attempt to change boiler demand among operating boilers to optimize efficiency may result in additional fuel demand swings.

Unsteady fuel feed rates will lead to uneven distribution of fuel on the grate. It also can contribute to increased incidences of fuel system pluggage which further exacerbates the problem and leads to a vicious cycle.

Co-firing RDF with other grate fired solid fuels such as stoker coal or wood chips is another pre-combustion methodology for CO control. Co-firing with these higher heating value fuels increases furnace temperature and encourages CO destruction. This method is available but usually prohibitive due to the cost of the fuel and the operational and maintenance costs considerations. Operators of plants designed to co-fire solid fuels have found that higher grate temperatures lead to slagging problems on the grate, and have discontinued co-firing.

As previously discussed, injection of overfire air is a post-combustion CO control technique that is widely used by RDF-fired facility operators. The technique is employed to oxidize the CO in a high temperature, highly turbulent area of the furnace above the firing grate so that carbon reburn will occur. The most common problem associated with OFA injection is determining where to put the air and at what pressure it should be injected. CO gases are primarily emitted from the firing grate in a stratified manner and usually do not become evenly dispersed in the flue gas stream until after passing through the boiler's convection pass. Because the firing grate is in constant motion, excess CO emitted from the grate as a result of fuel piling becomes a moving target. To combat this problem, a grid of OFA should be generated above the firing grate to oxidize the excess CO regardless of where it is being generated on the grate. More specifically, OFA should be injected at different elevations and progressive pressures to allow for greater penetration and full coverage of the furnace. RDF facilities having success controlling CO inject OFA at elevations from 5 to 50 feet above the grate and vary OFA header pressures from 5 inches to 30 inches wg. Each individual boiler should be evaluated to determine the optimum locations for, and pressures of, injected OFA.

The use of auxiliary burners is becoming more widespread for CO control applications. Burners are located above the firing grate and fired with approximately 20% excess air to create a conducive environment for secondary combustion of the CO gases emitted from the firing grate. Clean burning natural gas is the fuel of choice, however, #2 fuel oil can be used if natural gas is unavailable. Dual fuel burners are recommended where gas curtailments are a potential concern. The burners must be strategically located above the furnace to reburn CO gases released from the firing grate. Control can be manual or automatic using a furnace temperature control signal and/or the CEMS corrected CO signal. This post-combustion CO control methodology, much like co-firing solid fuels, can be prohibitive due to the fuel and equipment costs. However, if CO compliance is unachievable through other methods described previously, introduction of a second fuel may be necessary to continue operation.

CO - DIOXIN EMISSION CORRELATION

The Subpart C_b CO emission concentration limit was developed with the assumption that both Dioxin/Furan and CO emissions were indicators of complete combustion. In a strict sense, this may be true, especially for plants built without acid gas control and designed for higher allowable particulate emissions. For these plants, dioxin emissions may be extremely high.

In the case of the Norfolk Naval Shipyard Steam Plant in Portsmouth, VA, operated by the Southeastern Public Service Authority of Virginia, Dioxin/Furan emissions are well below the proposed limits while CO levels have not been maintained below the proposed limit. This facility was recently retrofitted with spray dryer absorbers and fabric filters. Furthermore, Penobscot Energy Recovery Company (PERC) in Orrington, Maine has encountered a similar non-correlation as illustrated in Figure 7 which demonstrates that the perceived correlation between low CO concentration levels and low Dioxin/Furan levels does not always exist.

CONCLUSIONS

Control of CO emission levels in a RDF-fired application is not achieved by one single action or installation of a certain piece of equipment. The plant operator must be cognizant of all variables which affect CO emissions.

Most operators of large RDF plants have the tools and knowledge to operate within the new emission concentration limit for CO. Others will need to embark upon programs to identify and implement the changes required to lower CO emission concentration levels.

Based on the results of this study and considering the economics, the following recommendations would be made for an operator considering a CO control program. These items are listed in descending order of importance:

1. Implement boiler control program changes to level-out fuel feed rates to the greatest extent possible.

2. Develop OFA testing matrix and conduct tests to establish OFA settings and UGA/OFA splits for various loads and fuel conditions.

3. Consider boiler geometry retrofits which will result in better combustion.

4. Retrofit fuel feed system.

5. Implement natural gas and/or fuel oil auxiliary burners for CO control.

Actual equipment retrofits would require significant capital expenditures. Before any retrofit is implemented, an operator would need to extensively study the costs and benefits to justify the project and to make sure it would be effective in reducing CO emissions. The only benefit of such a retrofit may be achieving the future CO emission concentration limit. The actual benefit to the environment should be considered by governmental agencies prior to imposing costly permit requirements on individual operators.

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8. Ronald Davies, Plant Manager, Honolulu Resource Recovery Venture, Honolulu, Hawaii

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Table 1. Comparison of Surveyed Units' Liberation Rate

Facility	Units	Capacity TPD/unit	Boiler Manufacturer	Boiler MCR steam/hr	Furnace Vol. cu-ft	Typical CO ppmdv	Liberation Btu / hr / cu-ft
Palm Beach	2	900	B&W CCZ	322,000	32,787	55	14,030
MERC	2	300	B&W CCZ	105,000	7,092	90	21,151
Elk River	1	600	B&W	176,000	16,895	125	14,882
SEMASS	3	900	Riley Stoker	280,000	42,120	140	9,497
PERC	2	350	Riley Stoker	133,400	11,232	200	16,967
Columbus	4	500	B&W	165,000	9,185	300	25,663
SPSA	4	500	CE, VU-40	180,000	17,658	400	14,562
Honolulu	2	890	CE, VU-40	244,000	26,532	100	13,138

Table 2. Comparison of Surveyed Units' Heat Release Rate

Facility	Units	Capacity TPD/unit	Boiler Manufacturer	Boiler MCR lbs steam/hr	Grate Area sq-ft	Typical CO ppmdv	HR Rate Btu / hr / sqft
Palm Beach	2	900	B&W CCZ	322,000	630	55	730,159
MERC	2	300	B&W CCZ	105,000	220	90	681,818
Elk River	1	600	B&W	176,000	399	125	630,147
SEMASS	3	900	Riley Stoker	280,000	600	140	666,667
PERC	2	350	Riley Stoker	133,400	294	200	648,202
Columbus	4	500	B&W	165,000	342	300	689,223
SPSA	4	500	CE, VU-40	180,000	399	400	644,468
Honolulu	2	890	CE, VU-40	244,000	396	100	880,230

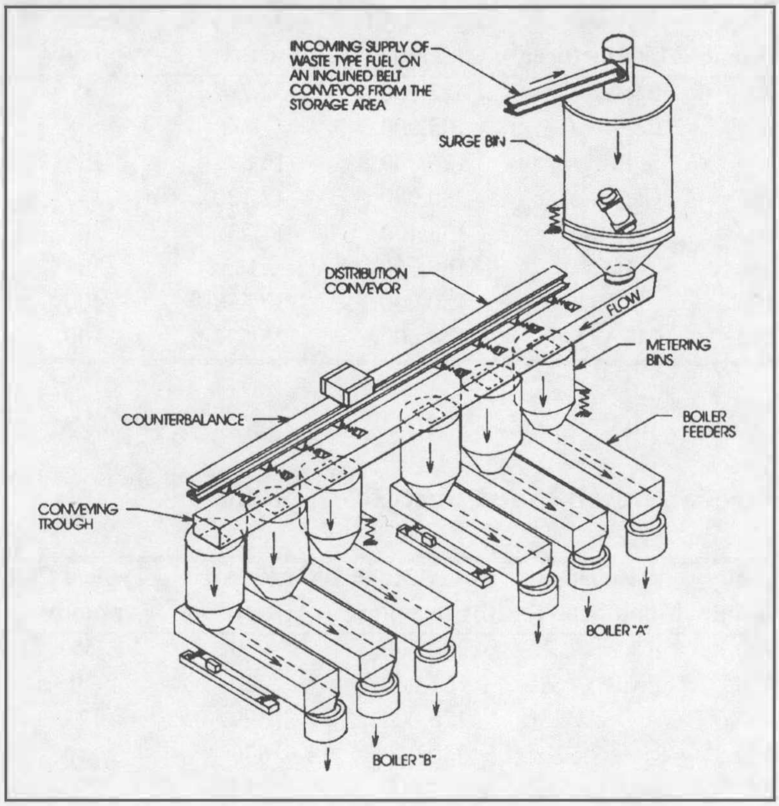

Figure 1

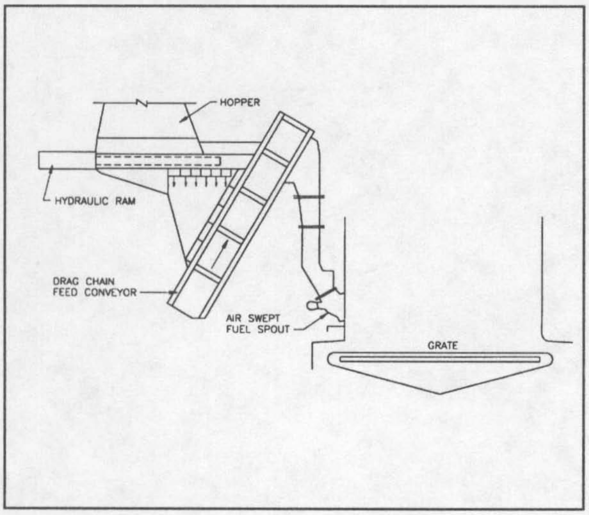

Figure 2

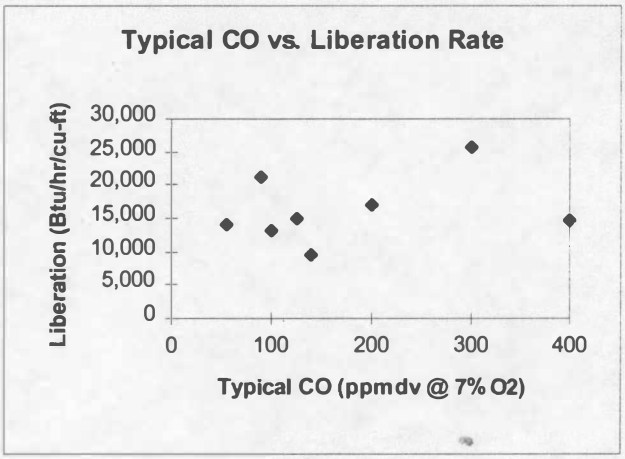

Figure 3

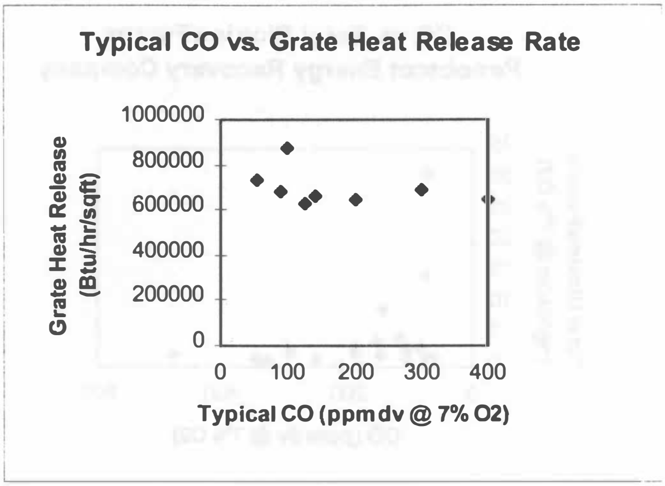

Figure 5

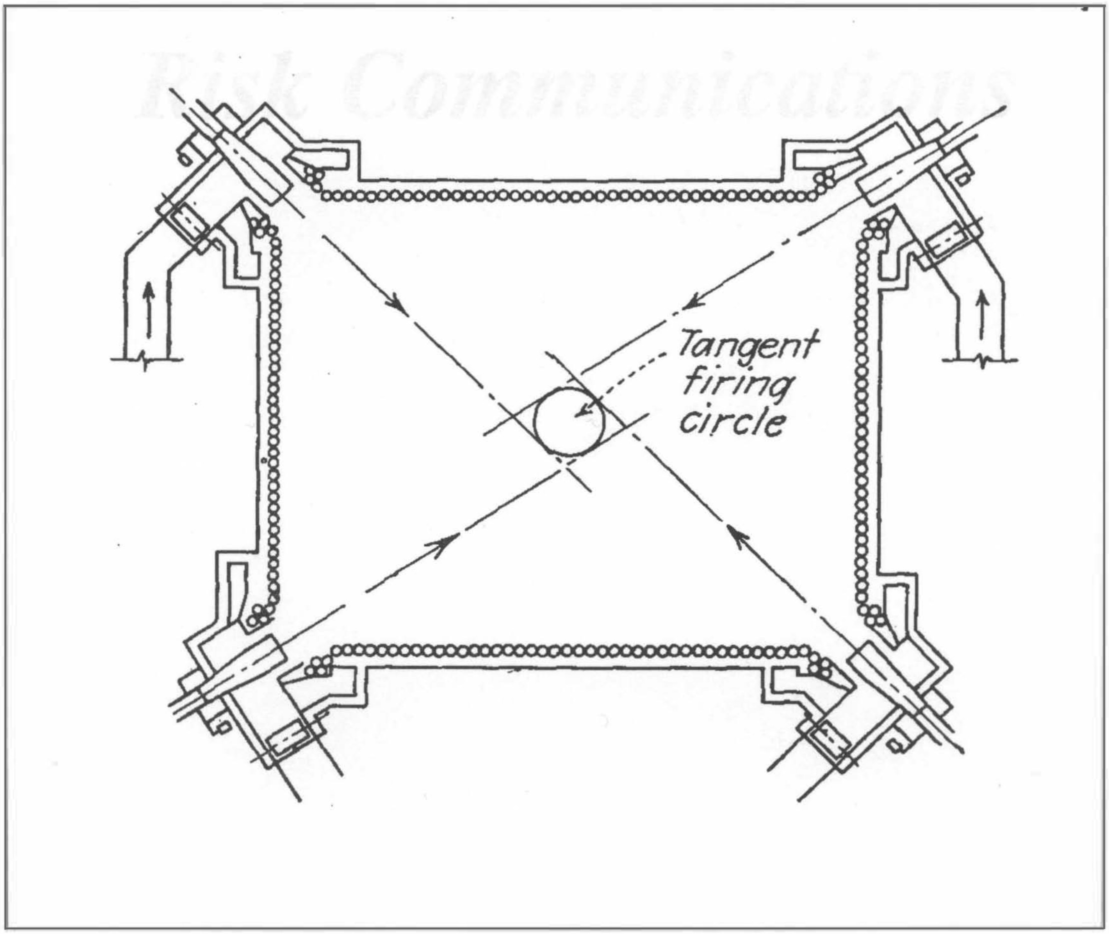

Figure 6

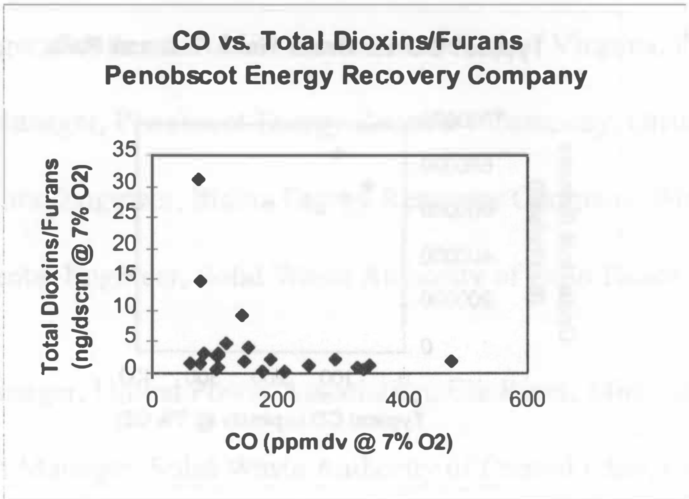
CO vs. Total Dioxins/Furans
Penobscot Energy Recovery Company
Total Dioxins/Furans (ng/dscm @ 7% O2)
35
30
25
20
15
10
5
0
0
200
400
600
CO (ppmdv @ 7% O2)

Figure 7