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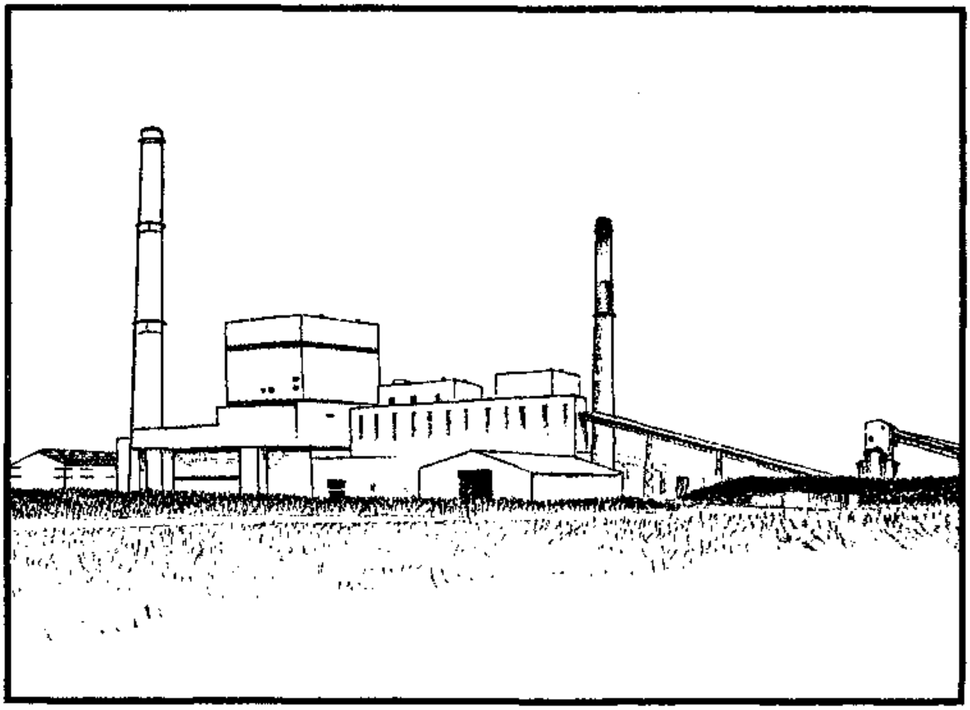
Volume I
Pilot Study of Combustion Emissions Variability



PILOT STUDY OF INFORMATION OF SPECIFIC COMPOUNDS FROM COMBUSTION SOURCES

by

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TASK 3
FINAL REPORT

EPA Contract No. 68-01-5915
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Prepared for

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Office of Pesticides and Toxic Substances
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PREFACE

This final report was prepared for the Environmental Protection Agency under EPA Contract No. 68-01-5915, Task 3. The task was directed by Dr. Clarence L. Haile. Substantial portions of the effort were subcontracted to Southwest Research Institute under Dr. Carter P. Nulton and to Gulf South Research Institute under Mr. William L. Yauger, Jr. This work was completed in coordination with statistical design studies conducted by Research Triangle Institute under Dr. Robert M. Lucas. This report was prepared by Dr. Clarence L. Haile and Dr. John S. Stanley with substantial contributions from Dr. Robert M. Lucas, Ms. Denise K. Melroy, Dr. Carter P. Nulton, and Mr. William L. Yauger, Jr.

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TABLES (continued)

SECTION 1

INTRODUCTION

This pilot study was conducted as a prelude to a nationwide survey of organic emissions from major stationary combustion sources. The primary objectives of the pilot study were to obtain data on the variability of organic emissions from two such sources and to evaluate the sampling and analysis methods. These data are used to construct the survey design for the nationwide survey. The compounds of interest are polynuclear aromatic hydrocarbons (PAHs) and chlorinated aromatic compounds, including polychlorinated biphenyls (PCBs), polychlorinated dibenzo-*p*-dioxins (PCDDs), and polychlorinated dibenzofurans (PCDFs). Of particular interest is 2,3,7,8-tetrachlorodibenzo-*p*-dioxin (TCDD). In addition, total cadmium was also determined in special samples from both plants to meet special Environmental Protection Agency (EPA) needs.

Midwest Research Institute (MRI) was responsible for overall task management,specifying the sampling and analysis methods, assisting in the collection of samples, receiving samples at the plant sites, shipping the samples to the analysis laboratories, and conducting all sample analyses. MRI was assisted in this effort by two subcontractors. Southwest Research Institute (SwRI) assisted in sampling, exercised sample control, and conducted most of the analyses for samples from the first plant. Gas chromatographic/mass spectrometric confirmation of PCBs, PCDDs, and PCDFs was conducted by MRI. Gulf South Research Institute (GSRI) provided similar assistance for the second plant.

The statistical design of the pilot study was constructed by Research Triangle Institute (RTI). RTI also conducted statistical analysis of the resulting emissions data and constructed the design for the nationwide survey. The results of the statistical analysis are summarized in Section 9 of this report. The survey design is summarized in a report to the EPA Office of Toxic Substances.[1]

TRW, Inc. was responsible for conducting the field sampling and data collection. The results of TRW's efforts are described in two reports to EPA's Industrial Environmental Research Laboratory in Research Triangle Park.[2,3] The body of these reports are contained in Appendices A and B.

A summary of the results of this study is contained in Section 2 of this report. Section 3 presents recommendations for future work. Brief descriptions of the two combustion sources are contained in Section 4. The sampling and analysis methods are described in Sections 5 and 6. Sections 7 and 8 present the field test data and analytical results. The analytical quality assurance results are summarized in Section 9. Section 10 presents the emissions results and Section 11 is a statistical summary of the emissions results.

SECTION 2

SUMMARY

Two major stationary combustion sources, a municipal incinerator and a co-fired (refuse-derived fuel plus coal) power plant, were studied to determine the variability of organic emissions between sources and over a designated time period for each plant. The pilot study results served as a basis for structuring the survey design for a nationwide survey[1] for organic emissions from stationary combustion sources.

All inputs and outputs (including fuel, air, water, ash, and flue gas) that were influenced by the combustion process at each facility were sampled for a minimum of 11 days. Daily flue gas samples (20 m^3) were collected concurrently at the inlet and outlet of the control devices using a modified Method 5 sampling train. The solid and aqueous inputs and outputs from each plant were collected six times per day (at roughly 4-hr intervals).

The samples were extracted and analyzed for total organic chlorine (TOCl), PAHs, PCBs, PCDDs, and PCDFs. A limited number of samples were analyzed for cadmium. The TOCl procedure (more correctly, total extractable organic halide) was developed for this study to provide a sensitive measure of the variability of chlorinated organic emissions.

The TOCl emissions from the municipal incinerator and the co-fired power plant differed and were variable within the test duration for each plant. The flue gas accounted for more than 80% of each plant's TOCl emissions. The TOCl emissions averaged 322 mg/hr from the municipal incinerator and 246 mg/hr from the co-fired power plant. The variability of the TOCl results was the key element in the construction of the nationwide survey design.[1]

A number of specific compounds including chlorinated benzenes and chlorinated phenols were detected in the flue gas from the municipal incinerator. The sum of the organic chlorine concentrations attributable to these specific compounds is comparable to the TOCl results. Fewer chlorinated compounds were identified in the flue gas extracts of the co-fired plant and were generally present at lower concentrations than in extracts from the municipal incinerator.

Polycyclic organic compounds including PAHs, PCDDs and PCDFs were identified in the flue gas extracts from the municipal incinerator. Some PAHs and PCBs were also identified and quantitated in the flue gas from the co-fired power plant, but PCDDs and PCDFs were not detected.

The mean concentration observed for total PCBs from the municipal incinerator was 42 ng/dscm (dscm = dry standard cubic meter), compared to an average of 19 ng/dscm from the co-fired power plant. However, the order of the average emission rate is reversed because of the lower flue gas flow rate of the refuse incinerator. The average PCB emission rates for the RDF/coal-fired power plant and the refuse incinerator were 6 mg/hr and 3.6 mg/hr, respectively. Because of the variability observed in the data, no significant differences between concentrations or emission rates between the two plants can be determined. The PCB isomer distribution ranged from dichlorinated to pentachlorinated compounds for the municipal incinerator and trichlorinated to decachlorinated compounds for the co-fired power plant. PCDDs and PCDFs were not identified in sample extracts from the co-fired power plant. However, several PCDDs and PCDFs were identified in composited sample extracts from the municipal incinerator. Trichloro- and tetrachlorodibenzofurans were the most abundant of the PCDDs and PCDFs in these extracts, averaging 300 ng/dscm and 90 ng/dscm, respectively. The specific PCDD isomer 2,3,7,8-tetrachlorodibenzo-p-dioxin (2,3,7,8-TCDD) was also identified in these extracts from the municipal incinerator and averaged 0.4 ng/dscm (average mass emission 34 µg/hr). This isomer was identified in these extracts using high resolution gas chromatography/high resolution mass spectrometry. This identification was confirmed by an independent laboratory using similar instrumentation.

The level of cadmium was also measured in the inputs and outputs for a limited number of sample days for each plant. The mass balance observed for the inputs and emissions of the co-fired power plant was fairly good. However, the agreement for cadmium inputs and emissions for the municipal incinerator was poor. This was likely due to the difficulties encountered in obtaining representative samples of the refuse burned at this facility.

SECTION 3

RECOMMENDATIONS

The nationwide combustion study should be conducted. The results in this report provide the basis for a sound statistical design for sampling and analysis procedures in future programs (i.e., municipal incinerators, coal-fired power plants, etc.).

Extraction studies should be undertaken with fly ash samples that have been shown to contain PCDDs and PCDFs. Analysis of such a material could provide a better measure of recovery efficiency of these compounds than from other similar solid materials.

The modified Method 5 sampling procedure used in this study is based on sound developments for particulate sampling coupled with adsorption of organic vapors on a resin of known properties. However, this sampling procedure should be rigorously evaluated for the collection efficiencies of PCDDs and PCDFs as an additional quality assurance measure.

The preliminary data presented in this report suggest that the TOCl measurement should be further evaluated for use as an indicator of chlorinated organic emissions. The development of a good TOCl measurement could significantly reduce the costs of obtaining large amounts of combustion source data.

Additional work should be conducted to improve the selective separation and detection of PCDDs and PCDFs. Current methods require labor-intensive extractions and cleanup procedures.

SECTION 4

PLANT DESCRIPTIONS

AMES MUNICIPAL POWER PLANT, UNIT NO. 7

The Ames Municipal Power Plant is owned and operated by the city of Ames, Iowa, and is located within the city limits. The coal-fired utility boiler tested at this plant was Unit No. 7, one of three units that have been modified to burn processed refuse as a supplemental fuel with coal. Unit No. 7, a pulverized coal suspension fired boiler, is used under normal operating condition. The other two units are operated under peak demand or when Unit No. 7 is down. This unit was originally designed to burn either coal or natural gas as the primary fuel. It was first brought into operation in 1968 and was modified to burn refuse-derived fuel (RDF) in 1975.

Unit No. 7 generally burns a mixture of Colorado coal, Iowa coal, and RDF. Generally, the ratio of the two types of coal varies, although during this particular testing period a 45 to 55% ratio of Colorado to Iowa coal was maintained in the pulverized coal mixture. Approximately 20% (by weight) of the total fuel prepared and fired at this facility was RDF and 80% was pulverized coal.

The RDF is produced at a separate Ames city facility located near the power plant. Raw refuse is sorted to remove glass and metals for recycling. The remaining material (largely papers and plastics) are milled and pneumatically conveyed to a storage bin. The RDF is fed from this bin to the boiler at the required rate. The maximum RDF feed rate is 8.5 tons/hr (7.7 metric tons/hr).

Pulverized coal is supplied to the furnace by tangentially orientated nozzles so that combustion is accomplished in a suspension. Approximately 20% of the total ash produced during coal-only firing is bottom ash. RDF is supplied to the furnace at a point just above the primary coal combustion zone. Moveable grates hold the residual RDF at the bottom of the coal combustion zone to enhance RDF combustion. The grates are lowered during bottom ash wasting and when RDF is not being fired.

The ash and slag deposited in the hopper are removed at least three times per day. An average of 758,000 liters/day (200,000 gal./day) of well water (sluice water) is used to remove the solid waste from the furnace bottom. This waste is drained to a holding pond where the ash is dredged out and stock piled. The water from the holding pond is allowed to percolate through the soil and eventually into a nearby river.

Electrostatic precipitators (ESPs) are used to remove particulates from the stack gases. The ESPs require at least 61 kw of the maximum 35,000 kw gross output of Unit No. 7. Fly ash collected in the ESP hoppers is pneumatically conveyed (3 times/day) to the bottom ash hopper drain system.

Additional information including schematics of the plant site, the flow system, Unit No. 7 design, and the solid waste recovery system is presented in the pilot test program engineering report provided by TRW (see Appendix A). Other tables in the TRW report list the boiler design data, the pulverizer specifications, the fan design performance parameters, performance characteristics of the ESP, and the predicted performance characteristics of Unit No. 7.

CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

The Chicago Northwest Incinerator is one of four municipal incinerators owned and operated by the city of Chicago (Illinois) and located within the city limits. This plant has four incinerators, each having a nominal burning capacity of 400 ton/24 hr day (363 metric tons/24 hr day). Each incinerator has a charging hopper, feed chute, hydraulic powered feeders and stoker, boiler, economizer and fly ash hoppers. Draft through the furnace is provided by forced draft fans, overfire air fans, and induced draft fans.

Mixed refuse from domestic sources is brought to the incinerator in trucks having a capacity of 5 tons (4,500 kg) or 25 cubic yards (19 m^3). The refuse varies considerably in consistency and moisture content seasonally and from load to load. All refuse is collected in a storage pit of 9,700 cubic yard (7,400 cubic yard) capacity. The refuse is not sorted prior to storage in the pit except for large items (e.g., furniture and large appliances) which are milled prior to storage in the pit. The refuse typically contains considerable quantities of automobile tires, small appliances, and similar discarded durable goods. The refuse is removed from the pit by one of three transfer cranes and is dumped directly into the four furnace feed hoppers. Refuse in the charging hopper of each incinerator flows by gravity from the hopper to three stoker feeders through a feed chute. The stoker feeders at the bottom of the feed chute push the refuse into the stoker by a reciprocating action.

Alternate lateral rows of grate steps have controlled continuous reciprocating action with the moving grate steps pushing in reverse direction to the flow of refuse. This action moves a portion of the burning refuse under the unignited material and thereby effects an agitation and blending of the whole burning mass. Combustion air entering from below the grates cools the grates, helps to agitate the burning refuse and supplies the oxygen which produces a maximum burn-out in the shortest length of grate travel.

The combustion air combines with the burning refuse to generate heat and raise the temperature of the flue gas to as high as 2000°F (1100°C). At rated burning capacity and based on 50% excess air (dry) the flue gas flow rate at 550°F (290°C) is estimated to be 142,300 actual cubic feet per minute (acfm) or 4,030 m^3/min. The flue gas passes upward through the furnace, through the boiler passes and finally through the economizer to the electrostatic precipitator. As it passes through the boiler it transfers heat to the water.

At the inlet to the electrostatic precipitator the temperature is reduced to approximately 500°F (260°C) because of the above heat exchange. During the passage of the flue gas through the boiler passes and economizer the heavier fly ash particles drop out. Hoppers are provided below the boiler and economizer for the collection of the particulates.

In order to obtain maximum combustion efficiency, the depth of the refuse bed is controlled by automatic discharge or clinker rollers located at the end of the grate. As the residue reaches this point it is dumped into an ash discharger and is quenched in water. The residue is pushed up an inclined slope that permits draining and produces a residue of less than 15% moisture. In addition to quenching, the ash discharger also serves as a water seal for the furnace and prevents infiltration of air into the furnace. The furnace operates under slight negative pressure.

The residue leaving each incinerator ash discharger passes through a hydraulically operated chute to one of two residue conveyors. The residue is screened to separate material larger than 2 in. (5 cm) in diameter. Hydraulic powered chutes are used to direct the flow of the residue away from the rotary screens and into a by-pass hopper.

The residue conveyors also receive and transport stoker grate siftings and fly ash accumulations from the boiler hoppers, economizer hoppers, and the electrostatic precipitators. Stoker grate siftings collect in six hoppers under each of the three stoker grate sections. Residue from the hoppers is removed from the plant by trucks. The weight of the residue leaving the plant is measured and recorded at the weighing station.

The boiler fly ash is collected in four hoppers, two of which discharge to the stoker grates. The other two hoppers are discharged directly through a common pipe to the residue conveyor. The fly ash from the economizer hoppers passes through a common pipe connected to the discharge end of a conveyor handling fly ash from the two electrostatic precipitator hoppers. The fly ash is deposited directly into the residue discharge chute.

The flue gas exiting the ESPs is vented to a 250-ft (76 m) high stack via an induced draft fan. Flue gases from two identical units are discharged from a single stack via a breaching.

A more detailed description of the plant operation and schematics of the plant site, the flow system, and the flue gas and grab sampling locations is presented in the TRW pilot test program engineering report (see Appendix B).

SECTION 5

SAMPLING METHODS

FLUE GAS

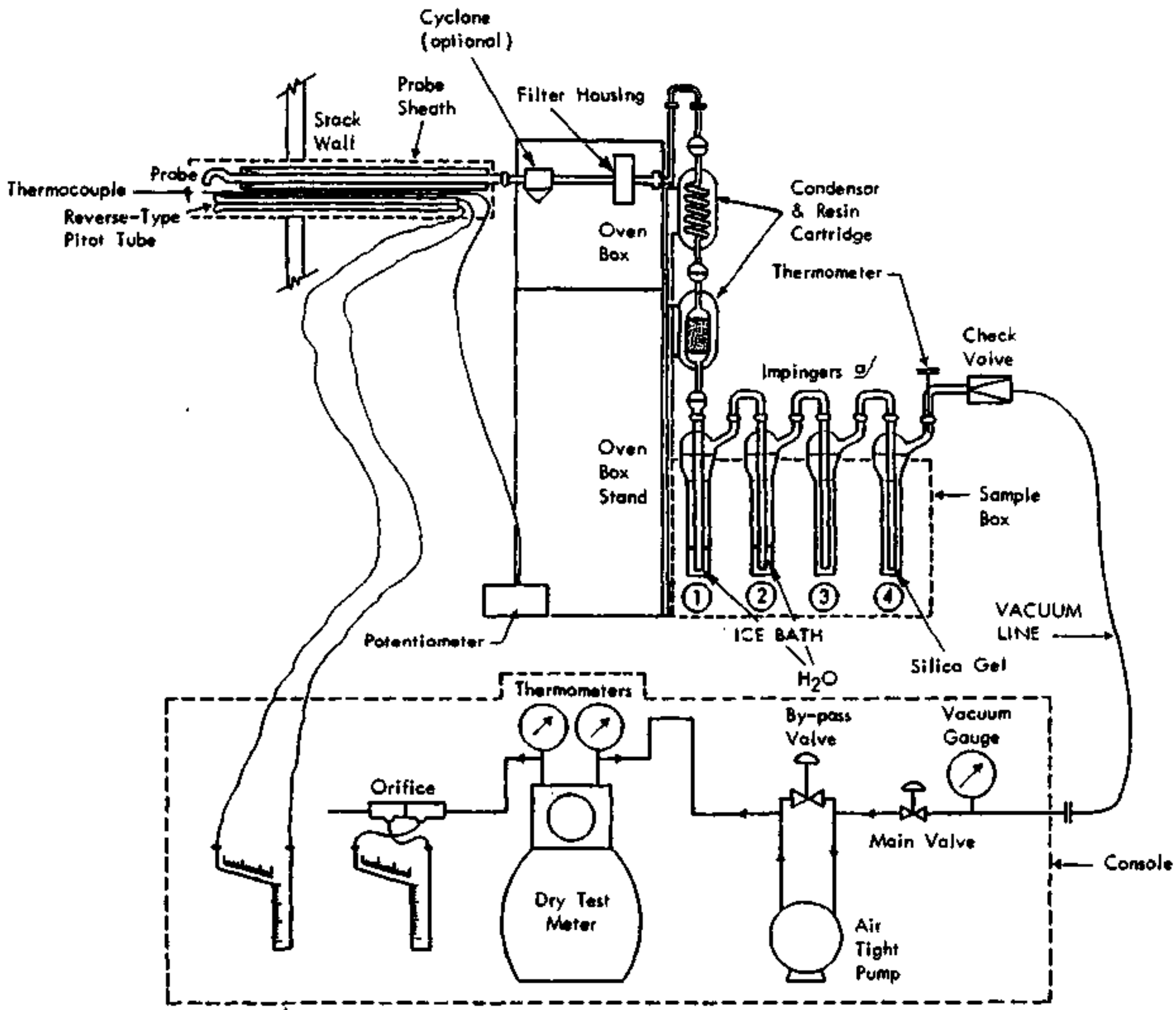
Flue gas sampling for organic compounds was accomplished concurrently at points both inlet and outlet to the electrostatic precipitators using two modified Method 5 sampling trains (shown in Figure 1) at each location. Figure 2 shows the locations of sampling ports on a typical unit. The sampling crew collected 10 m^3 (10 ± 1 m^3) samples with each sampling train by extracting the flue gas at rates approximating the flue gas velocity for each plant. Cadmium was sampled at the ESP outlet using a single Method 5 sampling train. The standard train was operated the same as depicted in Figure 1, but without condensor and the XAD-2 sorbent trap. EPA Method 5 Procedures[4] for particulate sampling were followed for both organic and inorganic sampling procedures, except that 10 m^3 was sampled with each organic train.

Detailed descriptions of the Method 5 calibration and actual sampling procedures for specific ducts and stacks at the Ames Municipal Power Plant and Chicago Northwest Incinerator have been presented in the respective field data reports (Appendices A and B). Additional details on the pretest preparation and sample recovery procedures are described in a methods manual for the nationwide combustion source survey.[5] The flue gas sampling at the Ames facility was conducted both on the duct just before the electrostatic precipitator and on the stack. Sampling for organics was to be performed for 14 consecutive days with an additional 3 days sampling for particulate cadmium. However, due to extreme weather conditions only 11 days of concurrent inlet and outlet samples were collected. Eight additional inlet samples were also collected.

The flue gas sampling at the Chicago plant was conducted at the duct inlet to the electrostatic precipitator and at the duct leading from the precipitator to the stack. Despite boiler down time and equipment malfunction, 11 days of organic samples (including concurrent inlet and outlet flue gas) were taken.

A complete sampling train, including resin trap filter and impinger solutions was set up as a train background (blank) at each plant. The train was taken to normal operating temperature and allowed to remain at this temperature for 1 hr.

Upon completion of testing, the sampling equipment was brought to a clean laboratory area for recovery. Each sampling train was kept in a separate area to prevent sample mixup and cross contamination. The individual sample train components were recovered as follows:



a/ Impingers 1, 3 and 4 are of the Modified Greenburg-Smith Type
Impinger 2 is of the Greenburg-Smith Design
Impinger 1 and 2 Contain 100 ml Water
Impinger 3 Empty
Impinger 4 Contains 200-300 Grams Silica Gel

Figure 1. Modified Method 5 train for organics sampling.

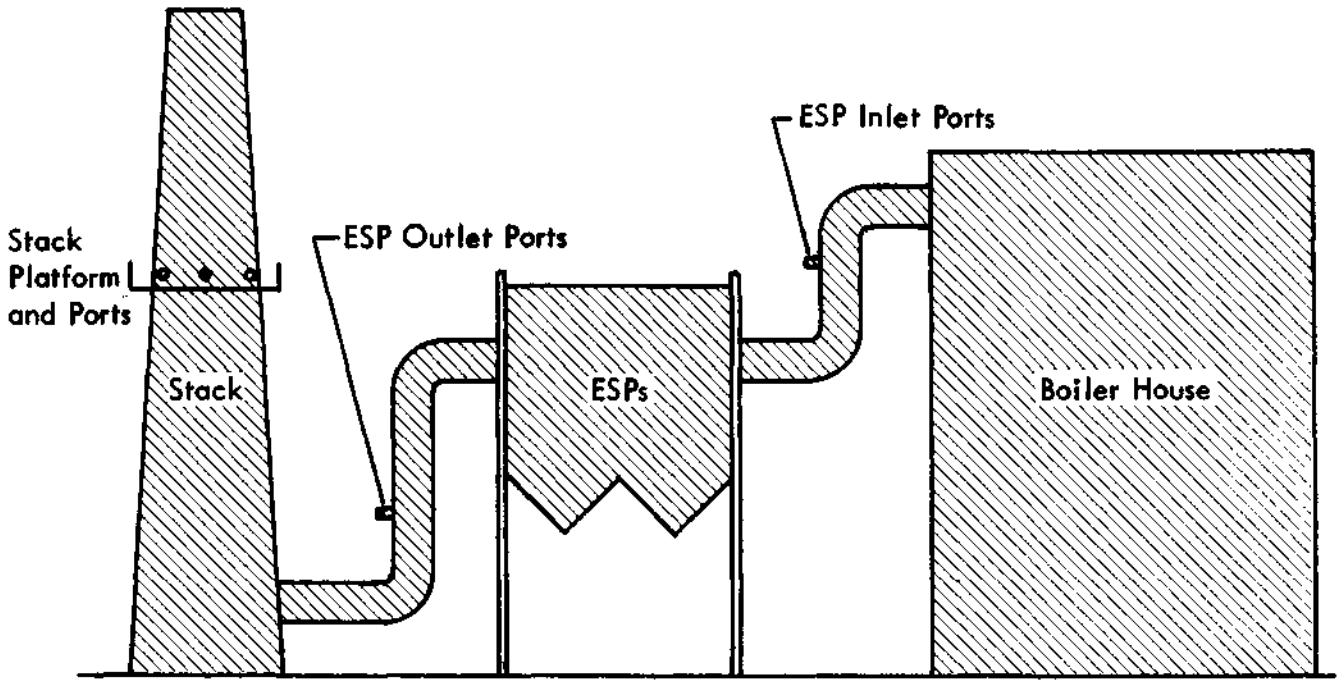


Figure 2. Locations of flue gas sampling ports on a typical combustion unit.

- Dry particulate in cyclone - cyclone flasks were transferred to cyclone catch bottle.

- Probe was wiped to remove all external particulate matter near probe ends.

- Filters were removed from their housings and placed in proper containers.

- After recovering dry particulate from the nozzle, probe, cyclone, and flask, these parts were rinsed with distilled water to remove remaining particulate. They were subsequently rinsed with glass distilled acetone and cyclohexane and put into a separate container. All rinses were retained in an amber glass container.

- Sorbent traps were removed from the train, capped with glass plugs, and given to an on-site MRI representative.

- Condensor coil, if separate from the sorbent trap, and the connecting glassware to the first impinger was rinsed into the condensate catch (first impinger).

- First and second impingers were measured, volume recorded and retained in an amber glass storage bottle. The impingers were then rinsed with small amounts of distilled water, acetone and cyclohexane. These rinsings were combined with the condensate catch. Rinse volumes were also recorded.

- The volumes of the third and fourth impingers were measured and recorded. Solutions were discarded.

- Silica gel was weighed, weight gain recorded and regenerated for further use.

To maintain sample integrity, all containers were amber glass, with TFE-lined lids.

PLANT BACKGROUND AIR

A high volume air sampler was used to collect organic compounds and cadmium associated with particulates in the air used for combustion. The samples were collected on 8 in. x 10 in. (20 cm x 25 cm) glass fiber filters. A high volume sampler was placed on the roof of each facility to obtain a representative background of outside ambient air, rather than sampling air inside the building that could have been contaminated or influenced by the combustion process.

SOLID AND AQUEOUS MEDIA

Solid and aqueous samples that directly contact the combustion process were collected several times during each 24-hr period according to schedules provided by RTI. Four solid sample types were collected from the Ames plant, coal, ESP hopper ash, bottom ash, and RDF. ESP ash, refuse, and combined ash were sampled at the Chicago plant. Combined ash includes mixed ESP ash and bottom ash since the design of the Chicago ash handling system did not allow separate access to bottom ash. All solid samples were collected six times per day at roughly 4-hr intervals.

Some solid samples were accessible from more than one nominally equivalent point in the plant. In these cases, samples were taken from specific points according to a randomized scheme provided by RTI. Hence, coal was sampled from two feed streams, RDF was sampled from four feed streams, and ESP ash was sampled from two collection hoppers at the Ames plant based on this scheme. Similarly, bottom ash from the Ames plant and bottom ash and refuse from the Chicago plant were sampled from specific sectors of the exposed material according to the randomized scheme. Figure 3 shows the sector systems used in sampling bottom ash from the Ames and Chicago plants. Raw refuse was sampled at the Chicago incinerator from the two sides of the feed hopper.

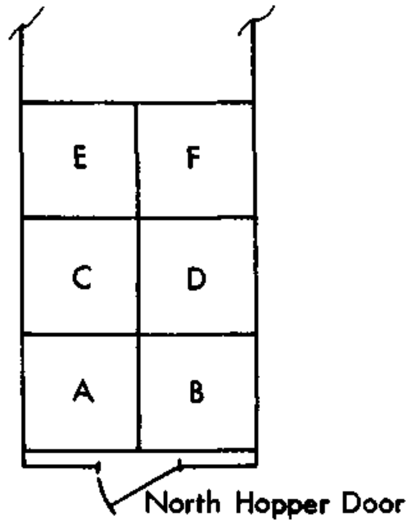
The aqueous streams sampled at Ames included cooling tower blowdown water, well water, and bottom ash quench overflow. Only city tap water (plant intake water) was sampled at the Chicago facility. Liquid streams that did not flow continuously were allowed to purge for 3 min prior to obtaining samples. Sample containers were rinsed three times with sample liquid prior to being filled with that liquid. The streams sampled and frequency of sampling were as follows:

- Bottom ash quench overflow water was sampled twice per shift, for a total of six samples per 24-hr period.
- Cooling tower blowdown feed for the bottom ash quench system was sampled once per day.
- Three well water samples were collected over the testing period.
- City tap water was sampled once per day.

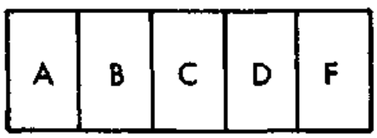
CONTINUOUS MONITORING

The continuous monitoring data collected for the two different plants included: (1) oxygen [O_2] concentrations, (2) carbon dioxide [CO_2] concentrations, (3) carbon monoxide [CO] concentrations, (4) hydrocarbon concentrations [THC] [C_1 through C_6] and (5) ambient temperatures. On-line monitoring was performed at the inlet of the electrostatic precipitators (ESP) at both plants and in the duct leading from the exit side of the ESP to the induced draft fan at the Chicago Northwest Incinerator and at the 100 ft (30 m) level on the stack at the Ames Municipal Power Plant.

A stainless steel filter connected to a 3-ft (91-cm) probe was inserted into the sample port for each sample location. Heat traced line was run from the sample port to a gas conditioner. Vacuum pumps were used to draw the inlet and outlet sample gas from the sample ports through the gas conditioner



Ames Municipal Electric System, Unit No. 7
Bottom Ash Hopper



Chicago Northwest Incinerator, Unit No. 2
Residue Discharge Chute

Figure 3. Sector schemes for sampling bottom ash.

and to the analytical instruments. An automatic timer switched the continuous monitoring equipment from inlet to outlet every 15 min.

The average values for O_2, CO_2, CO and THC recorded during each test period are presented in Section 8 of this report with a summary of the flue gas testing parameters. A more detailed description of the continuous monitoring data is presented in Appendices A and B.

PROCESS DATA COLLECTION

In order to fully characterize the operation of the two different combustion facilities and to designate periods of dramatic changes in the performance of a particular unit, numerous operating parameters were recorded throughout the flue gas sampling periods, as well as on a 24-hr basis. This information included mass flow data for fuels (coal, fuel oil, and RDF), periods of soot blowing, unit downtime, steam flow rate, steam pressure, steam temperature, feedwater flow rate, feedwater temperature, combustion air flow rate, combustion air temperature, percent excess oxygen, induced and forced fan pressures, furnace draft, furnace temperature, flue gas temperature, and ambient temperature and ambient pressure.

The process data averages based on 24-hr periods and the flue gas test durations are presented in Section 7 of this report. Data for these parameters taken on an hourly basis are presented in detail in the Appendices.

SECTION 6

ANALYSIS METHODS

ORGANICS

The analysis methods for organics were designed to provide qualitative and quantitative determinations of several specific analytes and to provide semiquantitative information on any additional polychlorinated aromatic compounds identified. The specific analytes included eight PAH compounds (listed in Table 1), PCBs, PCDDs, and PCDFs. Special emphasis was placed on highly selective and sensitive procedures for determining 2,3,7,8-TCDD.

TABLE 1. PAH COMPOUNDS SELECTED

Benzo[a]pyrene
Pyrene
Fluoranthene
Phenanthrene
Chrysene
Indeno[1,2,3-cd]pyrene
Benzo[g,h,i]perylene
Anthracene

Samples were also assayed for total organic chlorine (TOCl) to provide a general measure of the variability of chlorinated emissions. Since it was anticipated that concentrations for many specific compounds would be near minimum detectable levels, the variabilities observed for specific compounds may be more representative of measurement error than emission variabilities. The sensitivity of the TOCl procedure should allow more reliable detection of the variability of emissions for chlorinated organics.

A tiered scheme was used to economize on the total number of analyses required. The tier 1 operations, schematically shown in Figure 4, included sample extraction, TOCl assays, capillary gas chromatographic (HRGC) screening for halogenated compounds and hydrocarbons, and PAH analysis by capillary gas chromatography/mass spectrometry (HRGC/MS). Extract analysis by capillary gas chromatography with Hall electrolytic conductivity and flame ionization detectors (HRGC/Hall-FID) provided a sensitive screen for halogenated compounds that was used to aid the identification of specific halogenated compounds in the HRGC/MS data. Some of the individual grab samples were composited to form daily and shift composite samples prior to extraction for tier 1 analysis. The sample compositing scheme was provided by RTI.

The tier 2 analyses, also shown in Figure 4, focused on very sensitive and selective determinations of PCBs, PCDDs, and PCDFs. Extracts were analyzed by HRGC/MS operated in selected ion monitoring mode (HRGC/MS-SIM). Suspected responses for PCDDs and PCDFs were confirmed by using high resolution mass spectrometry (HRGC/HRMS-SIM). In addition, three extracts were submitted to the EPA laboratory at Research Triangle Park for collaborative confirmation of PCDDs and PCDFs.

The analytical quality assurance program included analyses of method spikes, method blanks, and field blanks in addition to the use of stable isotope-labelled surrogate compounds spiked into all samples to provide some analytical recovery data for all samples. Scanning HRGC/MS analyses were conducted using a stable isotope-labelled internal standard, d_{10}-anthracene. HRGC/HRMS-SIM analyses for TCDD employed $^{37}Cl_4$-2,3,7,8-tetrachlorodibenzo-p-dioxin. In addition, two sets of check samples, one set for TOCl and one set for specific chlorinated aromatic compounds, were sent to the two laboratories conducting the tier 1 analyses.

The analytical methods used are described in detail in the subsections that follow. Additional details of the analytical procedures are described in methods manual for the nationwide combustion source survey.[5]

Tier 1 Methods

Sample Preparation and Compositing--

Flue gas samples--The contents of the two modified Method 5 sampling trains used at each sampling point on each day were analyzed as a single sample. That is, the four trains used each sampling day (except for several days at the Ames site on which outlet flue gas was not sampled) comprised daily samples for outlet and inlet flue gas. Hence, the corresponding sample components from both trains were extracted together, i.e., filters, cyclone catch, train rinsings, and resin cartridges. All extracts resulting from the two trains were then combined.

All filters and cyclone catches were weighed prior to extraction to allow estimation of particulate emissions. However, the filters were not desiccated to constant weight according to the Method 5 procedures in order to maintain sample integrity for subsequent organic analyses. Hence, the particulate emissions estimates may not be valid.

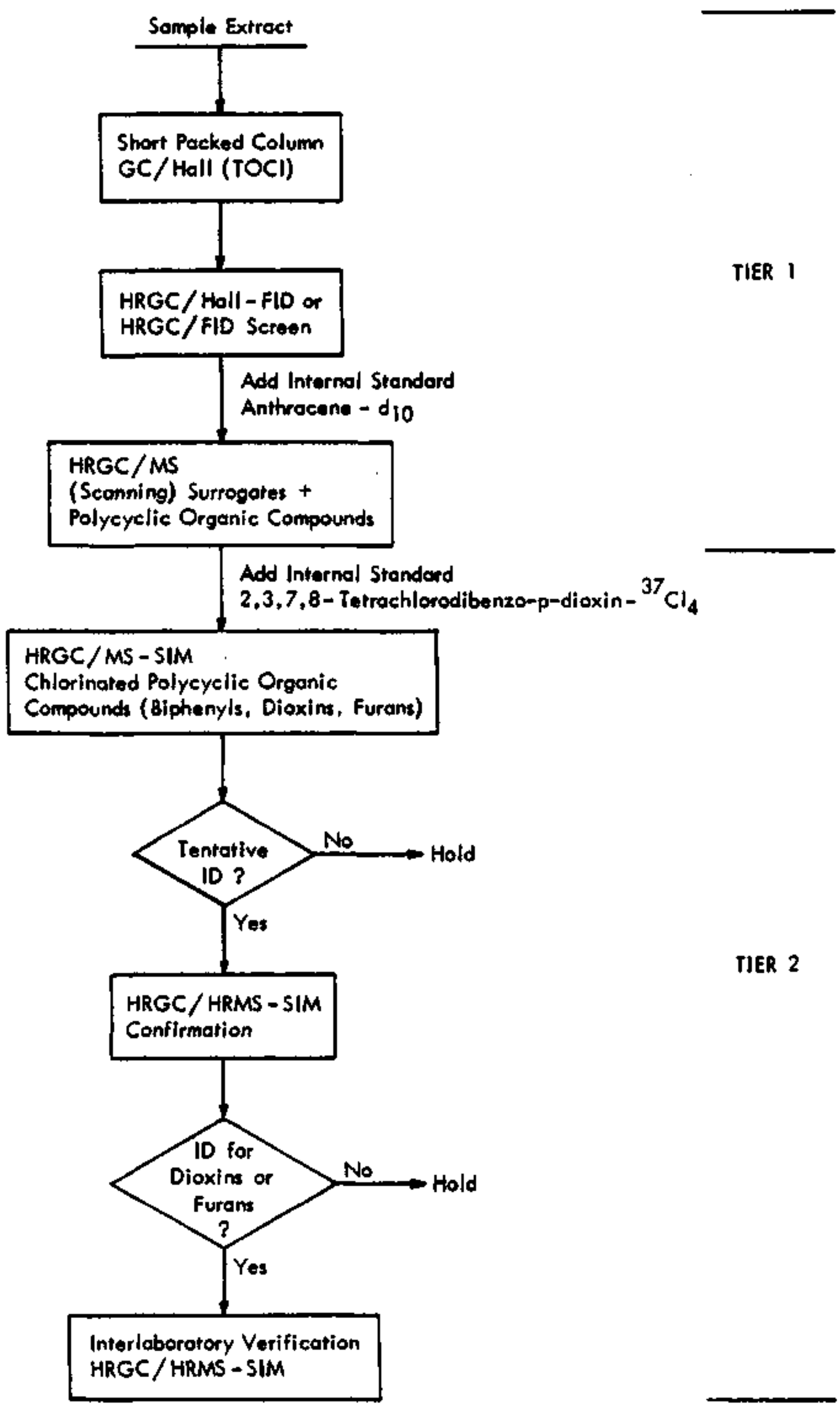


Figure 4. General analytical scheme.

Grab samples--Portions of the ash, fuel, and aqueous samples were composited according to a schedule provided by RTI to form daily and shift composites for each sample type for selected sampling days. Fly ash, bottom ash, and coal from the Ames site were prepared prior to compositing by pulverizing in a ceramic ball mill with stainless steel balls.

Plant background air samples--The single combustion air sample collected each day was extracted and analyzed individually. Prior to extraction, the filters were weighed to allow estimation of the total particulate catch.

Sample Extraction--

Solid samples--In order to determine the most appropriate extraction procedure, a number of solvent and extraction systems were evaluated using samples of Ames fly ash spiked with selected PAH's and 1,2,3,4-TCDD. Chlorinated solvents were avoided in order to minimize the possibility of producing chlorinated species during the extraction. Preliminary evaluations of simple sample-solvent contact techniques added by mechanical or ultrasonic agitation produced low recoveries. Subsequent evaluations were focused on Soxhlet and reflux procedures. Table 2 summarizes the results of evaluations of seven sample pretreatment and solvent system combinations using Ames fly ash spiked with selected PAHs and 1,2,3,4-TCDD. Pretreatment with water and Soxhlet extraction with benzene provided the highest recovery for all spiked compounds. The average recovery for the nine compounds was 81%. The range of recoveries obtained with this procedure was 56 to 107%.

The influence of pretreatment with water on the extractability of the target compounds is not clear. However, a general improvement in recoveries was observed for extractions with acetone/cyclohexane azeotrope when water was added to the ash prior to extraction. Similar effects have been reported for soil and sediment extraction by many researchers. Possibly, the water hydrates cations in the ash that tend to associate with the mobile π-cloud of polynuclear species so that they are more easily extractable.

Some researchers have reported good recoveries with procedures involving pretreatment with aqueous acid and extraction with aromatic solvents, e.g., pretreatment with 1 N HCl and extraction with toluene.[6] However, this procedure was determined to be unsatisfactory for several reasons. Acid pretreatment may encourage degradation of some compounds. Reflux or Soxhlet extraction with toluene must be conducted at a higher temperature than for benzene (the boiling points of toluene and benzene are 111 and 80°C, respectively) so that thermally unstable and relatively volatile compounds may be lost. In addition, toluene extracts cannot be conveniently concentrated using Kuderna-Danish evaporation over a steam or hot water bath.

All solid samples were Soxhlet extracted with benzene for 8 to 16 hr. The entire sample was extracted for the flue gas train components. Twenty-gram aliquots of coal, refuse, refuse-derived fuel (RDF), bottom ash, and fly ash were extracted. The fly ash was mixed with 10 ml of prepurified water just prior to analysis. All samples were spiked with the two surrogate spiking compounds, d_8-naphthalene and d_{12}-chrysene, just prior to extraction. However, since the extracts for various flue gas components were later combined, only one component for each flue gas sample was selected for surrogate

TABLE 2. RECOVERY OF SELECTED PAHs AND 1,2,3,4-TCDD FROM AMES FLY ASH

	% Recovery						
Compound	A	B	C	D	E	F	G
Phenanthrene	62	76	60	63	62	46	102
Anthracene	49	67	48	63	49	42	107
Fluoranthene	60	61	65	68	60	25	94
Pyrene	64	60	65	68	64	24	86
1,2,3,4-TCDD	72	54	74	75	72	67	81
Chrysene	38	40	NS[a]	NS	38	15	73
Benzo[a]pyrene	26	28	35	52	26	8	69
Indeno[1,2,3-c,d]pyrene	15	20	27	40	15	0	58
Benzo[g,h,i]perylene	17	24	25	41	17	0	56
Average	45	48	50	59	44	25	81

Note: A. Soxhlet 16 hr, cyclohexane, dry fly ash (20 g).
B. Same as A except 5 ml H_2O + 5 ml acetone added to fly ash.
C. Soxhlet 16 hr, acetone/cyclohexane azeotrope (67% acetone).
D. Same as C except 5 ml H_2O added to fly ash (80% cyclohexane).
E. Soxhlet 16 hr, cyclohexane/ethanol azeotrope + 10 ml water on fly ash (20 g).
F. Reflux 4 hr with 250 ml H_2O + 50 ml toluene.
G. Soxhlet 16 hr with benzene + 10 ml H_2O added to 20 g fly ash.

a NS = No chrysene in spike.

spiking. The component selected was varied so as to provide some recovery data for all components.

The extracts from coal, refuse, and RDF were washed with three 100-ml portions of prepurified water to remove polar interferences. The extracts from all solid samples were dried by passage through short columns of pre-extracted anhydrous sodium sulfate before concentration to 2 to 10 ml in Kuderna-Danish evaporators. The extracts were further concentrated under a gentle stream of dry nitrogen. The final extract volume was typically 1.0 ml. However, some extracts were analyzed at volumes ranging from 0.20 to 10.0 ml. All extracts were spiked with the internal standard for scanning HRGC/MS, d_{10}-anthracene, prior to analysis.

Aqueous samples--All aqueous samples, i.e., flue gas rinses, first impinger waters, overflow waters, raw waters, etc., were batch extracted in separatory funnels with three 60-ml portions of cyclohexane. As in the case of the solid samples, the aqueous samples were spiked with the surrogate spiking compounds just prior to analysis. The resulting extracts were dried and concentrated to 0.20 to 1.0 ml according to the procedures described for solid samples.

TOCl Assay--

The TOCl contents of all extracts were determined using a simplified GC/Hall procedure. A short packed column and a rapid temperature program were used to elute all chromatographable compounds with volatilities equal to or greater than dichlorobenzene as a single peak. The TOCl contents of sample extracts were determined by comparing the area response of the peak with that obtained for chlorinated standards. TOCl results were expressed as chloride. The specific parameters used by SwRI and GSRI for TOCl assays of the Ames and Chicago samples, respectively, are shown in Table 3. A sample TOCl chromatogram for an Aroclor 1254 PCB standard (GSRI procedure) is shown in Figure 5.

HRGC/Hall-FID Screening--

Sample extracts were screened by HRGC/Hall-FID prior to HRGC/MS analysis to provide a preliminary indication of their halogenated and hydrocarbon contents. In addition, the Hall responses were used to help identify elution times on which to focus examination of the subsequent mass spectral data for halogenated compounds. The specific parameters used by SwRI and GSRI are shown in Table 4. Fused silica capillary columns were used with Grob-type capillary injection systems operated in the splitless mode. GSRI did not have a fused silica column effluent splitter available; hence, extracts from the Chicago plant were screened using FID detection only.

Scanning HRGC/MS--

Sample extracts were analyzed by HRGC/MS to determine the target PAH compounds and to allow identification and quantitation of specific chlorinated compounds. The primary determinations of surrogate spiking compound recoveries were made from the HRGC/MS data. The chromatographic parameters utilized were essentially identical to those used for the HRGC/Hall-FID screening.

TABLE 3. TOCl ANALYSIS PARAMETERS

Parameter	SwRI (Ames samples)	GSRI (Chicago NW samples)
Column	0.9 m x 4 mm ID, glass	1.0 m x 2 mm ID, glass
Packing	2.5 cm of 10% SP-2100 UltraBond	3.8 cm of 2.5% SE-30 on 80/100 mesh Chromosorb G, rest of column filled with 80/100 mesh glass beads
Carrier gas	He at 60 ml/min	He at 30 ml/min
Column temperature	60°C for 3 min, then to 230°C at 40°C/min	60°C for 3 min, then to 250°C at 40°C/min
External standard compound	chlorobiphenyl	Aroclor 1254

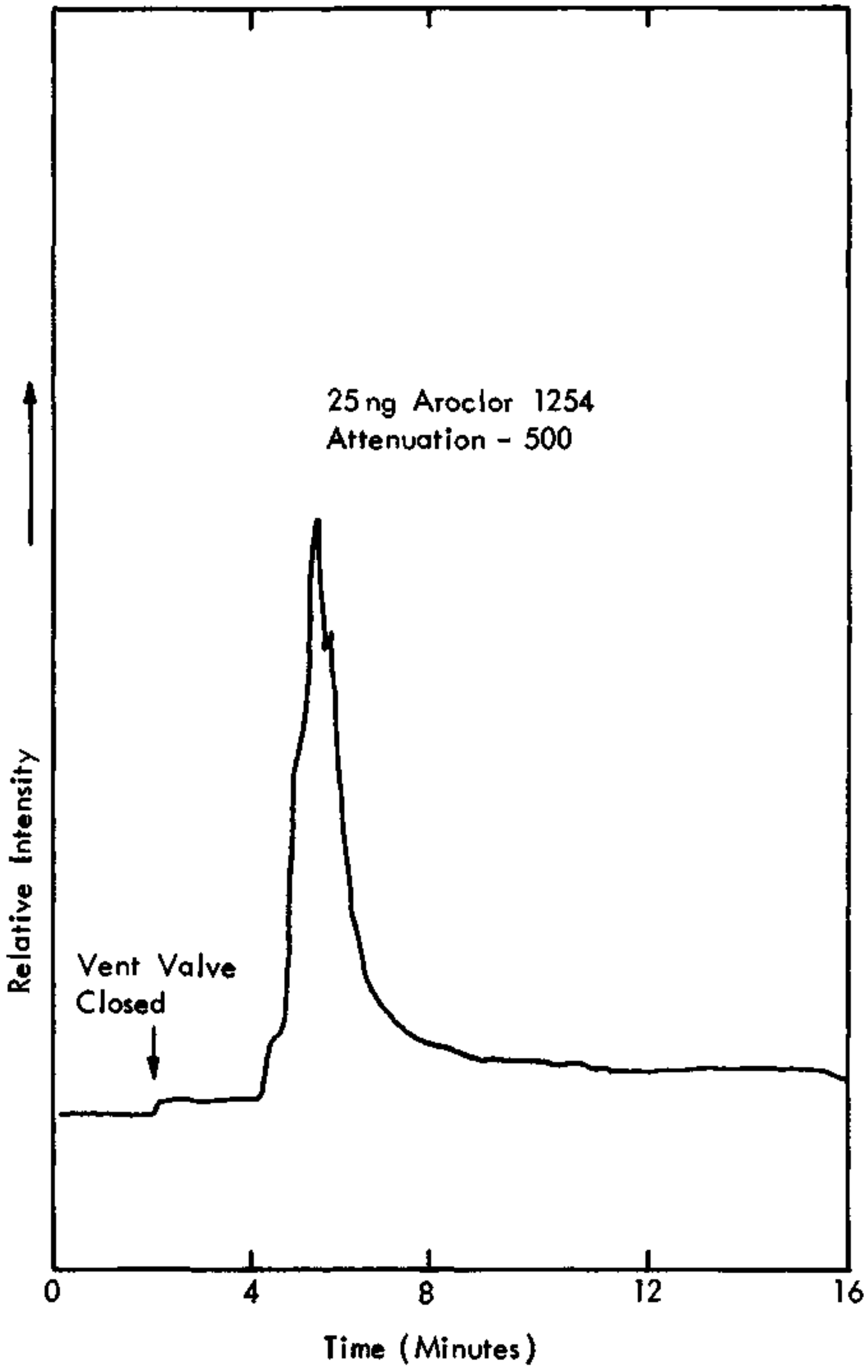


Figure 5. TOCl chromatogram for Aroclor 1254.

TABLE 4. HRGC SCREENING PARAMETERS

Parameter	SwRI (Ames samples)	GSRI (Chicago NW samples)
Column	30 m fused silica, wall coated with SE-30	30 m fused silica, wall coated with SE-30
Column temperature	100°C for 5 min, then to 300°C at 10°C/min	60°C for 2 min, then to 300°C at 10°C/min
Detectors	Hall-FID, 1:1 split	FID

During the runs, the spectrometer was repetitively scanned over the range m/e 35 to 550 at 1.0 sec/scan. The PAH compounds, including the surrogates, were identified using three extracted ion current plots (EICPs). The criteria for compound identification are coincident peaks in all EICPs at the appropriate retention time with the characteristic response ratios. Compounds identified were quantitated by comparing the EICP response for the most abundant ion with that for the same compound in a mixed standard solution.

Tier 2 Methods

Following completion of the tier 1 chemical analyses, RTI conducted a statistical analysis of the TOCl results and constructed a preliminary design for the nationwide survey based on the observed TOCl variabilities. The preliminary survey design specified sampling programs of 5 and 3 days duration for coal-fired and refuse-fired plants, respectively. Hence, in order to allow inclusion of the pilot study data in the survey data set, the extracts were composited prior to further analysis to simulate a 5-day test at the Ames plant and a 3-day test at the Chicago plant. The compositing scheme, provided by RTI, is shown in Table 5. The composite extracts for each composite day were prepared by combining equal volumes of daily composites from the designated sample days. This necessitated the preparation of daily composites from shift composite extracts or individual sample extracts for many samples and sample days.

TABLE 5. EXTRACT COMPOSITING SCHEME FOR TIER 2 ANALYSES

Composite day	Sample days combined: Ames samples	Sample days combined: Chicago samples
I	3/2, 3/15	5/6, 5/9, 5/16
II	3/13, 3/22	5/7, 5/10, 5/12
III	3/14, 3/19	5/11, 5/13, 5/15
IV	3/17, 3/20	
V	3/3, 3/23	

The composite extracts were screened by HRGC/Hall-FID or HRGC/FID prior to analysis for PAH compounds by scanning HRGC/MS, and for PCBs, PCDDs, and PCDFs by HRGC/MS-SIM. Only extracts for which positive responses were obtained for PCDDs and PCDFs were analyzed by HRGC/HRMS-SIM.

HRGC/Hall-FID and HRGC/FID Screening--

The composited extracts were screened by HRGC/Hall-FID (Ames samples) or HRGC/FID (Chicago samples) by the procedures described for Tier 1 screening except that fused silica capillary columns wall-coated with SE-54 were used.

Scanning HRGC/MS Analysis--

The HRGC/MS procedures employed for the composite extracts were essentially the same as was used for tier 1 analyses. The target PAH compounds were determined and any other compounds observed were identified by manual and computer-assisted spectral interpretation. Quantitative estimates for all compounds identified were based on responses versus responses for the same or similar compounds in standard solutions.

HRGC/MS-SIM Analysis--

All composite extracts were screened for the presence of PCDDs and PCDFs by HRGC/MS-SIM. The chromatographic parameters used by SwRI and GSRI for the Ames and Chicago extracts, respectively, were the same as were used for scanning HRGC/MS analyses. The ions selected for detection were the two most abundant ions in the molecular cluster for each compound. No positive responses were detected in any of the Ames extracts. Positive responses were detected in composite flue gas extracts from the Chicago plants. However, interfering materials in the extracts hindered reliable identifications.

Three composite flue gas extracts from the Chicago plant were cleaned by a vigorous base treatment, an acid treatment, and an alumina chromatographic procedure specifically developed for PCDD and PCDF assays. The composited extracts were split into two fractions each. One fraction was spiked with 1,2,3,4-tetrachlorodibenzo-p-dioxin and octachlorodibenzo-p-dioxin, and the other fraction was not spiked. The extracts were stirred with 45% aqueous KOH solution at ambient temperature for 3 hr. The mixture was extracted with hexane and the extract was washed with concentrated sulfuric acid until the washes remained colorless. The extract was concentrated and chromatographed on an alumina column using dichloromethane as the eluting solvent.

The cleaned extracts were analyzed at MRI by HRGC/MS-SIM. The instrumental parameters are listed in Table 6. These analyses were conducted using a high resolution mass spectrometer operated at 1,000 resolution (10% valley). Positive PCDD and PCDF responses were detected in all extracts. Since low resolution mass spectrometric analysis of PCDDs and PCDFs in environmental extracts may be obscured by the presence of similar chlorinated aromatic compounds (e.g., PCB's), these extracts were held for analysis by capillary gas chromatograpy/high resolution mass spectrometry using selected ion monitoring (HRGC/HRMS-SIM).

TABLE 6. HRGC/MS PARAMETERS USED FOR ANALYSES OF PCDDs AND PCDFs IN COMPOSITE CHICAGO NW FLUE GAS OUTLET EXTRACTS

Column	18 m fused silica wall-coated with SE-54
Column temperature	110°C for 2 min, then to 325°C at 10°C/min
Injector	J&W on-column
Spectrometer resolution	1,000 (10% valley)
Scan rate	1-2 sec/scan (3-5 ions/scan)
Ions selected (m/e)	
Trichlorodibenzo-p-dioxin	285.9, 287.9
Tetrachlorodibenzo-p-dioxin	319.9, 321.9
Pentachlorodibenzo-p-dioxin	353.9, 355.9
Hexachlorodibenzo-p-dioxin	389.8, 391.8
Heptachlorodibenzo-p-dioxin	423.8, 425.8
Octachlorodibenzo-p-dioxin	457.7, 459.7
Trichlorodibenzofuran	269.9, 271.9
Tetrachlorodibenzofuran	303.9, 305.9
Pentachlorodibenzofuran	337.9, 339.9
Hexachlorodibenzofuran	373.8, 375.8
Heptachlorodibenzofuran	407.8, 409.8
Octachlorodibenzofuran	441.7, 443.7

The Ames and Chicago composite flue gas outlet extracts were also analyzed at MRI for PCBs by HRGC/MS-SIM. The instrumental parameters and ions selected are shown in Table 7. The focused ions were switched several times during a single HRGC/MS run so that all PCB compounds could be analyzed in two runs, one for odd chlorine substitutions and a second for even chlorine substitutions. PCBs were quantitated by comparing the total area response for all

TABLE 7. HRGC/MS-SIM PARAMETERS USED FOR ANALYSIS OF PCBs IN COMPOSITE FLUE GAS OUTLET EXTRACTS

Column	15 m fused silica, wall-coated with DB-5 (a specially bonded SE-54 coating)
Column temperature	60°C for 2 min, then to 265°C at 8°C/min
Injector	Grob-type, splitless
Spectrometer resolution	1,000 (10% valley)
Scan rate	1-2 sec/scan (2-4 ions/scan)
Ions selected (m/e)	
Dichlorobiphenyl	221.9, 223.9
Trichlorobiphenyl	255.9, 257.9
Tetrachlorobiphenyl	291.9, 293.9
Pentachlorobiphenyl	323.9, 325.9
Hexachlorobiphenyl	357.8, 359.8
Heptachlorobiphenyl	393.8, 395.8
Octachlorobiphenyl	427.7, 429.7
Nonochlorobiphenyl	461.7, 463.7

compounds identified for a specific chlorine substitution with the area response for a specific isomer of the same chlorine substitution number. For example, total trichlorobiphenyls were quantitated against 2,5,2'-trichlorobiphenyl. The PCB isomers used for quantitation are listed in Table 8.

TABLE 8. PCB COMPOUNDS USED FOR DETERMINATIONS IN COMPOSITE FLUE GAS OUTLET EXTRACTS

2,2'-Dichlorobiphenyl
4,4'-Dichlorobiphenyl
2,5,2'-Trichlorobiphenyl
2,4,2',4'-Tetrachlorobiphenyl
2,4,2',5'-Tetrachlorobiphenyl
2,3,4,5,6-Pentachlorobiphenyl
2,4,6,2',4',6'-Hexachlorobiphenyl
2,3,4,2',3',4'-Hexachlorobiphenyl
2,3,4,5,6,2',5'-Heptachlorobiphenyl
2,3,4,5,2',3',4',5'-Octachlorobiphenyl
Decachlorobiphenyl

HRGC/HRMS-SIM Confirmatory Analysis of PCDDs and PCDFs--

PCDDs and PCDFs were identified and quantitated in the composite Chicago flue gas outlet extracts by HRGC/HRMS-SIM. The instrumental parameters employed were the same as for low resolution screening at MRI except that the spectrometer was operated at 10,000 resolution (10% valley). The selected ions monitored are listed in Table 9.

In order to achieve maximum sensitivity while minimizing the number of HRGC/HRMS-SIM runs, ions for a specific chlorine substitution for both dioxins and furans were monitored in a single run. For example, trichlorodibenzo-p-dioxins and trichlorodibenzofurans were analyzed in the same run. However, the tetra-substituted compounds were analyzed in separate runs to provide even better sensitivity for the most toxic PCDDs and PCDFs.

The PCDD and PCDF compounds identified were quantitated by comparing the total area response for all compounds of a specific chlorine substitution with the area response for a specific isomer of the same chlorine substitution number. The specific PCDD and PCDF isomers used for quantitation are listed in Table 10. Compounds for which no corresponding authentic compound was available were quantitated against the most similar compound. Hence, hexachlorodibenzofurans were quantitated against hexachlorodibenzo-p-dioxin. The response factor used for pentachlorodibenzodioxins was the average of responses for tetra- and hexa-isomers. Tetrachlorodibenzo-p-dioxins were quantitated using $^{37}Cl_4$-2,3,7,8-tetrachlorodibenzo-p-dioxin as an internal standard. Since discrete isomers were not identified, only totals were determined for each chlorine substitution.

A separate HRGC/HRMS-SIM analysis with a 60-m Carbowax column was used to determine 2,3,7,8-tetrachlorodibenzo-p-dioxin. The instrumental parameters are shown in Table 11. The Carbowax column, although providing good separation of specific tetra-isomers, required longer analysis times and caused signficant peak broadening. Hence, it was not used for general PCDD and PCDF analyses. The internal standard method employing ^{37}Cl-labeled compound was used for quantitation.

Quality Assurance Procedures

The analytical quality assurance program consisted of the use of surrogate spiking compounds in all samples; the use of internal standards for most GC/MS analyses; analyses of field blanks and method blanks; and interlaboratory comparison studies for selected determinations. Surrogate spiking compounds were used as the primary analytical quality indicators. The two stable isotope labeled surrogates, d_8-naphthalene and d_{12}-chrysene, were spiked immediately prior to extraction into all samples at 5 to 10 times the limits of detection. The surrogate concentrations were determined using scanning HRGC/MS data. The surrogate compound recoveries provide indications of overall quality of the extraction and extract concentration procedures.

All scanning HRGC/MS analyses were conducted using d_{10}-anthracene as the internal standard. Tetrachlorodibenzo-p-dioxin analyses by HRGC/HRMS-SIM were conducted using $^{37}Cl_4$-2,3,7,8-tetrachlorodibenzo-p-dioxin.

TABLE 9. IONS MONITORED DURING HRGC/HRMS CONFIRMATORY ANALYSIS OF PCDDs AND PCDFs IN COMPOSITE CHICAGO NW FLUE GAS OUTLET EXTRACTS

Compound	m/e
Trichlorodibenzo-p-dioxin	285.9355, 287.9325
Tetrachlorodibenzo-p-dioxin	319.8965, 321.936
$^{37}Cl_4$-2,3,7,8-Tetrachlorodibenzo-p-dioxin (internal standard)	327.8847
Pentachlorodibenzo-p-dioxin	353.8887, 355.8858
Hexachlorodibenzo-p-dioxin	389.8157, 391.8127
Heptachlorodibenzo-p-dioxin	423.7688, 425.7659
Octachlorodibenzo-p-dioxin	457.7377, 459.7347
Trichlorodibenzofuran	269.9406, 271.9376
Tetrachloridibenzofuran	303.9017, 305.8987
Pentachlorodibenzofuran	337.8938, 339,8909
Hexachlorodibenzofuran	373.8208, 375.8178
Heptachlorodibenzofuran	407.7739, 409.7710
Octachlorodibenzofuran	441.7428, 443.7398

TABLE 10. PCDD AND PCDF COMPOUNDS USED FOR DETERMINATIONS IN COMPOSITE CHICAGO NW FLUE GAS OUTLET EXTRACTS

1,2,4-Trichlorodibenzo-p-dioxin
1,2,3,4-Tetrachlorodibenzo-p-dioxin
2,3,7,8-Tetrachlorodibenzo-p-dioxin
Hexachlorodibenzo-p-dioxin (isomer unknown)
Octachlorodibenzo-p-dioxin
2,3,7,8-Tetrachlorodibenzofuran
Octachlorodibenzofuran

TABLE 11. HRGC/HRMS PARAMETERS USED FOR ANALYSIS OF 2,3,7,8-TETRACHLORODIBENZO-p-DIOXIN IN COMPOSITE CHICAGO NW FLUE GAS OUTLET EXTRACTS

Column	60 m fused silica, wall-coated with Carbowax 20M
Column temperature	110°C for 2 min, then to 220°C at 10°C/min
Injector	J&W on-column (1 µl injection)
Spectrometer resolution	10,000 (10% valley)
Scan rate	1 sec/scan (3 ions)
Ions selected	
Tetrachlorodibenzo-p-dioxin	319.8965, 321.8936
$^{37}Cl_4$2,3,7,8-Tetrachloro-p-dioxin (internal standard)	327.8847

Analyses of field blanks and method blanks (i.e., laboratory blanks) provided indications of possible sample contamination due to contact with the sampling and analysis equipment as well as general sample and extract handling. Field blanks comprised 10 to 15% of the total samples and included unused components of the flue gas sampling train, a complete sampling train for each plant (as described in Section 5), unused sample containers, and aliquots of solvents used for sample recovery at the plant. Method blanks were extracts prepared in the same manner as sample extracts although no samples were extracted.

Since the tier 1 analyses were conducted by two laboratories (SwRI and GSRI), interlaboratory comparison studies were conducted to check the comparability of the resulting data. Three such studies were conducted. Comparability of TOCl results was investigated by a set of TOCl check extracts prepared by MRI and by an exchange of selected sample extracts between SwRI and GSRI. Check samples of fly ash spiked with selected chlorinated compounds were also prepared by MRI and analyzed by SwRI and GSRI using HRGC/Hall and scanning HRGC/MS. In addition, extracts in which positive responses were observed for PCDDs and PCDFs by HRGC/HRMS-SIM were submitted to Robert Harless at EPA's Environmental Monitoring and Support Laboratory in Research Triangle Park for collaborative analysis. The results of these analyses are described in Section 9.

CADMIUM

Samples of fly ash weighing 0.1 g or samples of bottom ash weighing 0.1 to 1 g were placed in 150-ml beakers that had been precleaned with nitric acid. Ten milliliters of aqua regia were initially added to each ash sample. The samples were gently heated and allowed to reflux until the evolution of yellow fumes subsided. An additional 5 ml of aqua regia was then added, and the ash was allowed to continue digesting. Another 5 ml of aqua regia was added to all samples, and the samples were allowed to digest for at least 20 more min.

The samples were permitted to cool, and all of the material was transferred to 50-ml plastic centrifuge tubes. Centrifugation was accomplished at 2,500 rpm for approximately 5 min. The supernatant liquid was transferred by Pasteur pipets to the original beakers. Deionized water was added to the residue in the centrifuge tubes, the mixtures were agitated, the tubes were once again centrifuged, and the supernatant was added to that in the original beakers. This washing procedure was repeated again. The residue remaining in the centrifuge tube was then washed three times with a 5% (v/v) nitric acid solution. For each washing, 5 ml of the acid solution was added to each sample, and the samples were centrifuged and processed as described above.

The final solutions in the beakers (approximately 85 ml) were returned to the hot plate and heated gently until the volume of the solution was reduced to 20 ml. The solutions were allowed to cool, filtered through Whatman No. 4 filter paper, and diluted to 50 ml with deionized water.

A modification of this procedure was used for the digestion of refuse and filter samples. Fifteen milliliters of aqua regia and 10 ml of deionized water were added to 1-g portions of refuse or to the entire air filter. Tap water and probe-rinse water were digested by adding 3 ml of concentrated nitric acid and 1 ml of concentrated hydrochloric acid to 200 ml of sample and heating gently until the volume was reduced to less than 50 ml. The digested sample was diluted to 50 ml with deionized water. Solutions prepared by digestion of solid samples were analyzed by flame atomic absorption spectrophotometry (AAS) using an air-acetylene flame. Water samples were analyzed by heated-graphite atomization AAS.

A comprehensive QA/QC control program was conducted for cadmium analyses. The program included analysis of the National Bureau of Standards coal fly ash standard reference material, aqueous solutions of cadmium prepared in-house, fortified and duplicate samples, and reagent blanks. Samples were usually digested and analyzed in groups of eight: four distinct samples, a duplicate of one of the original four which had been fortified with 10 μg of cadmium, a duplicate of another of the original four which was unaltered, a quality-control sample, and a reagent blank. The fresh dilutions of a standard solution of cadmium were prepared on each day of analysis and were used to calibrate the AAS.

The precision and accuracy of the analytical method used by GSRI were determined by analysis of a coal fly ash standard reference material from the National Bureau of Standards (NBS) and fortified fly ash from the Chicago

Northwest Incinerator. The average and standard deviation of the percentage of cadmium recovered by analysis of four replicate samples of the NBS coal fly ash was 98 ± 11. Analysis of seven replicate samples of incinerator fly ash showed the cadmium concentration to be 260 μg/g. The recovery of cadmium from the incinerator fly ash was determined by analysis of samples fortified with cadmium. The results of the recovery study are presented in Table 12. An average of 95 ± 15% of the cadmium was recovered from the fortified samples. SwRI provided QA measures in terms of analysis of all sample types spiked at the levels shown in Table 13.

TABLE 12. RECOVERY OF CADMIUM FROM FORTIFIED SAMPLES OF FLY ASH FROM THE CHICAGO NW INCINERATOR

Sample	Cadmium in original sample (μg/g)[a]	Cadmium added to sample (μg/g)	Cadmium determined in fortified sample (μg/g)	Percent cadmium recovered
1	260	100	330	70
2	260	99	370	111
3	260	100	360	100
4	260	97	350	93
5	260	100	360	100
6	260	100	370	110
7	260	100	340	80
Mean recovery				95
Standard deviation				15

a Average of seven replicate analyses.

TABLE 13. RECOVERY OF CADMIUM FROM FORTIFIED SAMPLES FROM THE AMES MUNICIPAL POWER PLANT

Sample type	Spike level	Recovery
Fly ash	0.5 μg/g	97
Bottom ash	0.5 μg/g	93
Refuse	0.1 μg/g	98
Coal	0.5 μg/g	94
Aqueous	4 μg/100 ml	110

SECTION 7

FIELD TEST DATA

AMES MUNICIPAL POWER PLANT, UNIT NO. 7

The field test activity at the Ames Municipal Power Plant took place from February 25, 1980 to March 28, 1980. All required tests were completed and all recovered samples were sent to SwRI for analysis.

A summary of the reduced data for flue gas sampling on a daily basis as calculated from the field data sheets is presented in Table 14. The following abbreviations are used throughout this report: DSCF = dry standard cubic feet, DSCM = dry standard cubic meters, ACFM = actual cubic feet per minute, DSCFM = dry standard cubic feet per minute, and DSCMM = dry standard cubic meters per minute. The data listed are corrected to standard conditions, i.e., 20°C (68°F) and a barometric pressure of 29.92 in. of mercury (1.0 atm). Percent isokinetic is the sampling velocity expressed as percent of the gas velocity in the stack or duct at the sampling points. Events that may have created uncertainties as to the quality of the flue gas sampling procedures are noted. Due to severe weather conditions, flue gas outlet samples were not collected on test days 3 to 11.

Process data was monitored on an hourly basis during the entire testing period. Table 15 presents a summary of the pertinent process data as averages for daily 24-hr plant operation and operation during the flue gas sampling durations. The process data gathered indicated that the operating conditions fluctuated in patterns related to the amount of electricity generation demand placed on the boiler, and on the type of fuel being burned to meet that demand. Overall fluctuation consisted of two components. The first component was the daily variation. The load peaked in the afternoon and fell to a minimum before dawn. The second type of variation was caused by sudden operational changes, which was due to reduced power generation for various reasons such as the buying of cheaper power from a private utility, or the reduction in flow of RDF to the boiler.

Unit No. 7 was generally operated between a range of 16 to 35 MW. Production over 35 MW placed considerable wear on the unit, and was avoided whenever possible. Production under 16 MW introduced instability and the possibility of large transient swings in operating conditions. Usually the boiler was operating close to one of these limits. It operated at 35 MW during peakloads because the load of the serviced community was over 35 MW. Production was reduced to 16 MW when off-peak power could be bought more cheaply from neighboring utilities.

TABLE 14. DAILY DATA SUMMARIES FOR FLUE GAS SAMPLING, AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Date (1980)	Test no.	Sampling location		Sample volume DSCF	Sample volume DSCM	Gas composition[a] O_2 %	Gas composition[a] CO_2 %	Gas composition[a] CO ppm	Gas composition[a] THC ppm	Stack temperature °F	Molecular weight	Moisture %	Velocity ft/sec	Gas flow[b] ACFM	Gas flow[b] DSCFM	Gas flow[b] DSCMM	Isokinetic rate %
3-2	1	Inlet	North[c]	204.62	5.80	4.48	12.79	18.00	< 2	334.31	29.01	9.95	33.55	247,700	147,000	4,162	63.83
			South	262.52	7.43	4.48	12.79	18.00	< 2	311.78	29.35	7.15	29.09				89.01
		Outlet	1&4[d]	214.10	6.06	6.34	11.31	15.00	< 2	320.93	29.30	6.32	22.69	296,000	182,000	5,153	86.20
			2&3[d]	243.02	6.88	6.34	11.31	15.00	< 2	309.92	29.31	6.24	24.79				93.99
3-3	2	Inlet	North[e]	173.54	4.92	4.38	13.80	-	< 2	351.55	29.34	8.39	37.78	650,300	376,000	10,650	-
			North[e]	126.93	3.60	4.33	13.80	12.00	< 2	373.36	29.32	8.59	42.94				95.73
			South[f]	212.05	6.01	4.33	13.80	12.00	< 2	234.83	29.41	7.81	46.61				80.98
			South[f]	101.52	2.88	4.33	13.80	11.00	< 2	369.90	29.39	7.97	37.15				107.14
		Outlet	1&4	324.36	9.19	5.87	12.44	11.00	< 2	342.38	29.31	7.45	26.00	324,600	190,600	5,397	96.33
			2&3	307.31	8.70	5.87	12.44	11.00	< 2	336.94	29.31	7.48	26.10				90.33
3-4	3	Inlet	North	184.21	5.22	4.43	14.41	17.00	< 2	370.46	29.56	7.43	45.10	346,200	193,100	5,467	95.59
			South	252.78	7.16	4.43	14.41	17.00	< 2	352.55	29.30	9.48	43.72				92.25
		Outlet	1&4[g]														
			2&3[g]														
3-5	4	Inlet	North	256.88	7.28	4.41	14.56	18.00	< 2	361.09	29.49	8.14	43.20	333,300	189,800	5,375	91.43
			South	246.73	6.99	4.41	14.56	18.00	< 2	349.23	29.38	9.03	41.09				104.10
		Outlet	1&4[h]														
			2&3[h]														
3-6	5	Inlet	North	367.65	10.41	4.35	13.79	18.00	< 2	363.83	29.28	8.93	42.92	341,600	200,300	5,671	97.28
			South	323.17	9.15	4.35	13.79	18.00	< 2	347.46	29.18	9.72	43.48				90.54
3-7	6	Inlet	North	368.68	10.44	4.59	13.92	16.00	< 2	351.00	28.14	18.32	43.61	346,400	187,400	5,307	105.93
			South	365.42	10.35	4.59	13.92	16.00	< 2	335.86	29.27	9.18	44.01				99.65
3-8	7	Inlet	North	351.42	9.95	4.79	13.60	28.00	< 2	377.55	29.19	9.56	39.62	312,000	171,460	4,855	103.54
			South	333.61	9.45	4.79	13.60	28.00	< 2	359.83	29.16	9.75	39.28				105.53
3-9	8	Inlet	North[i]	74.03	2.10	7.1	11.6	25.00	< 2	316.83	29.19	7.79	30.27	492,300	286,000	8,098	95.60
			North[i]	294.81	8.35	7.1	11.6	25.00	< 2	364.73	29.16	8.05	30.38				98.51
			South[j]	121.92	3.45	7.1	11.6	25.00	< 2	344.38	29.20	7.78	36.43				106.23
			South[j]	140.22	3.97	7.1	11.6	25.00	< 2	315.88	29.17	8.02	27.38				50.55
3-10	9	Inlet	North[k]	130.81	3.70	3.7	13.9	25.00	< 2	352.09	29.31	8.59	45.23	351,900	196,200	5,555	88.84
			South[l]	193.61	5.48	3.7	13.9	25.00	< 2	330.65	28.25	17.13	43.77				89.58
3-11	10	Inlet	North	394.09	11.16	4.7	13.5	22.0	< 2	374.75	29.49	6.98	45.68	355,400	201,000	5,692	97.17
			South	383.01	10.85	4.7	13.5	22.00	< 2	356.59	29.30	8.48	44.20				105.29
3-12	11	Inlet	North[m]														
			South														

(continued)

TABLE 14 (continued)

Date (1980)	Test no.	Sampling location		Sample volume DSCF	Sample volume DSCM	Gas composition[a] O_2 %	CO_2 %	CO ppm	THC ppm	Stack temperature °F	Molecular weight	Moisture %	Velocity ft/sec	Gas flow[b] ACFM	DSCFM	DSCMM	Isokinetic rate %
3-13	12	Inlet	North	350.46	9.92	3.34	15.56	21.00	< 2	361.78	29.53	8.63	42.45	332,100	187,100	5,298	102.35
			South	369.82	10.47	3.34	15.56	21.00	< 2	340.61	29.54	8.54	41.41				102.23
		Outlet	1&4[n]	158.98	4.50	5.17	13.97	18.00	< 2	339.44	29.56	7.10	25.85	326,700	193,600	5,481	77.72
			2&3	305.29	10.35	5.17	13.97	18.00	< 2	315.08	29.28	9.37	26.58				91.73
3-14	13	Inlet	North	374.34	10.60	3.70	14.81	28.00	< 2	384.68	29.31	9.67	43.48	336,000	185,400	5,250	101.27
			South	352.11	9.97	3.70	14.81	28.00	< 2	375.70	29.30	9.70	41.49				107.20
		Outlet	1&4	367.77	10.42	5.31	13.18	30.00	< 2	365.94	29.14	9.60	24.34	306,506	170,300	4,822	99.80
			2&3	351.36	9.95	5.31	13.18	30.00	< 2	358.75	29.15	9.50	24.84				96.74
3-15	14	Inlet	North	276.77	7.83	6.31	12.59	22.00	< 2	368.23	29.27	8.14	30.85	240,400	135,400	3,834	102.11
			South	268.37	7.60	6.31	12.59	22.00	< 2	357.65	28.32	7.68	29.96				108.67
		Outlet	1&4	319.13	9.04	8.37	10.67	19.00	< 2	319.42	29.09	7.88	20.00	257,500	152,100	4,307	104.05
			2&3	307.00	8.69	8.37	10.67	19.00	< 2	356.65	29.10	7.83	21.31				96.83
3-17	15	Inlet	North	359.80	10.19	3.73	14.40	22.00	< 2	371.23	29.35	8.83	41.89	335,000	189,000	5,351	106.85
			South	390.47	11.06	3.73	14.40	22.00	< 2	348.41	29.44	8.17	42.84				99.99
		Outlet	1&4	406.86	11.52	5.43	12.90	22.00	< 2	354.56	29.21	8.71	26.01	332,100	191,500	5,423	107.18
			2&3	391.84	11.10	5.43	12.90	22.00	< 2	345.31	29.25	8.43	27.27				95.48
3-18	16	Inlet	North	369.16	10.45	3.82	14.39	23.00	< 2	381.96	29.29	9.36	43.06	335,900	186,300	5,274	100.17
			South	371.50	10.52	3.82	14.39	23.00	< 2	354.96	29.37	8.73	41.89				108.07
		Outlet	1&4	392.69	11.12	5.42	13.00	24.00	< 2	360.06	29.24	8.62	27.12	328,600	187,800	5,319	99.82
			2&3	353.25	10.00	5.42	13.00	24.00	< 2	357.50	29.18	9.09	25.60				93.81
3-19	17	Inlet	North	349.71	9.90	3.60	14.40	24.00	< 2	380.28	29.29	9.68	41.87	337,300	184,300	5,218	107.21
			South	368.75	10.44	3.60	14.40	24.00	< 2	361.59	29.37	8.68	43.42				97.16
		Outlet	1&4	374.30	10.60	5.30	13.00	26.00	< 2	373.12	29.03	10.28	26.75	334,500	185,300	5,246	101.03
			2&3	360.58	10.21	5.30	13.00	26.00	< 2	365.94	29.24	8.59	26.92				92.62
3-20	18	Inlet	North	347.89	9.85	3.80	13.80	22.00	< 2	350.96	29.33	8.31	42.13	333,100	191,000	5,408	92.21
			South[o]	368.08	10.42	3.80	13.80	22.00	< 2	342.65	29.39	7.86	42.11				104.31
		Outlet	1&4	356.20	10.09	6.00	12.50	17.00	< 2	338.12	29.29	7.79	24.63	321,200	188,400	5,334	95.09
			2&3	388.52	11.00	6.00	12.50	17.00	< 2	342.81	29.21	8.44	26.91				97.71
3-22	19	Inlet	North	363.46	10.29	3.60	14.20	38.00	< 2	348.64	29.36	8.54	41.65	321,400	185,000	5,239	105.17
			South	348.60	9.87	3.00	14.20	38.00	< 2	342.09	29.41	8.07	39.63				96.42
		Outlet	1&4	402.14	11.39	5.30	12.70	38.00	< 2	340.00	29.19	8.61	26.26	330.700	195,500	5,537	104.10
			2&3	401.16	11.36	5.30	12.70	38.00	< 2	330.60	29.24	8.23	26.81				99.03
3-23	20	Inlet	North	336.53	9.53	6.00	12.60		< 2	364.41	29.26	8.16	28.65	221,100	121,500	3,440	103.54
			South	330.73	9.37	6.00	12.60		< 2	355.41	28.69	12.74	27.26				115.99
		Outlet	1&4	301.61	8.54	9.70	10.00		< 2	354.13	28.82	9.73	16.63	226,400	132,800	3,761	110.45
			2&3	358.98	10.17	9.70	10.00		< 2	338.13	29.28	5.87	19.70				102.66

(continued)

TABLE 14 (concluded)

Date (1980)	Test no.	Sampling location		Sample volume DSCF	Sample volume DSCM	Gas composition[a] O_2 %	CO_2 %	CO ppm	THC ppm	Stack temperature °F	Molecular weight	Moisture %	Velocity ft/sec	Gas flow[b] ACFM	DSCFM	DSCMM	Isokinetic rate %
3-24	21	Outlet	1,2, 3&4	130.42	3.69	5.4	13.2		< 2	365.47	29.15	9.53	25.76	160.500	90,170	2,553	103.72
3-25	22	Inlet	North[p]														
			South[p]														
		Outlet	1,2, 3&4	122.79	3.48	5.4	13.2		< 2	356.40	29.10	9.92	24.58	153,200	87,030	2,464	101.06
3-26	23	Inlet	North	326.82	9.26	6.00	12.60		< 2	380.80	29.13	9.17	37.23	295,100	162,500	4,602	106.24
			South	344.98	9.77	6.00	12.60		< 2	382.45	29.14	9.09	37.40				118.43
		Outlet	1,2 3&4	138.67	3.93	4.80	13.70		< 2	364.38	29.24	9.26	26.42	164,700	93,240	2,640	106.64

a Average values for duration of test.

b Sum of flow through total inlet and total outlet.

c Low volume collected due to high leak rate at end. Volume was corrected for leak rate. Test quality fair.

d Low volume collected due to freezing of impingers. Test quality was good.

e At 250 min, noted nozzle pointed in wrong direction. Switched nozzle from 0.312 to 0.250 in. diameter tip to maintain isokinetic flow. Test quality was good for gas and fair for particulate.

f Switched nozzle from 0.312 to 0.237 in. diameter tip to maintain isokinetic flow.

g Due to snow and icy conditions, no sample was obtained.

h Cancelled per instructions of EPA until 3/13/80.

i Switched nozzle from 0.250 to 0.310 in. diameter tip to maintain isokinetic flow.

j Switched nozzle from 0.310 to 0.240 with diameter tip to maintain isokinetic flow.

k Probe found broken at 140 min, no samples retained. Test restarted with a new probe but only one half the duct was traversed due to freezing conditions. Test quality was fair.

l No solutions retained due to backup of H_2O_2 into all impingers. The resin, cyclone and filters were retained. Test quality was fair.

m QA test cancelled after 240 min due to leak at one of the probe tips.

n Test stopped at 296 min due to continual freezing of the train components. Test quality was fair to poor.

o Problems with the Batelle trap freezing and leaks in the Teflon line were encountered. The filter and traps were replaced to solve leak problems. Test quality was fair to good.

p QA test only. No samples were saved because nozzle was in the wrong direction and the test would not be duplicate.

TABLE 15. AVERAGE PROCESS DATA FOR THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

	24-hr Process data		Flue gas test duration process data	
	Mean	Standard deviation	Mean	Standard deviation
Steam flow rate (1,000 lb/hr)	255	35	289	50
Steam pressure (psig)	852	3	853	3
Steam temperature (°F)	892	3	896	5
Feedwater flow rate (1,000 lb/hr)	263	37	298	51
Feedwater temperature (°F)	366	16	377	19
Fuel feed rate 1 (1,000's lbs/hr) 2	30.4 30.6	3.2 3.4	33.1	4.2
Fuel oil (gal./hr)	10.7	11.2	-	-
I.D. fans amps	45	1	46	2
I.D. fans pressure (psig)	5.5	0.7	5.9	1.0
F.D. fans amps	29	1	30	1.1
F.D. fans pressure (psig)	4.0	0.6	4.5	0.9
Furnace draft (psig)	0.6	-	0.6	0.1
Flue gas temperature (°F)				
Boiler exit[a]	667	24	674	31
ESP inlet[a]	323	15	326	18
Ambient temperature (°F)	31	13	39[a]	20
Ambient pressure in. Hg	29.01	0.13	29.01	0.13

a Not total time means.

The daily mean of gross electrical output (24-hr basis) was typically between 29 and 32 MW due to boiler operation at full output for a large portion of the day. In fact, the hourly readings indicated that output was rarely below 35 MW between the hours of 8 AM and 10 PM or longer. During non-peak hours the boiler operated between 16 and 25 MW, depending on load and the amount of power being purchased from neighboring utilities.

Fuel consumption varied directly with the amount of electricity produced. Of the three types of fuels used in Unit No. 7 (coal, RDF, and fuel oil), coal was used in the largest quantity. The amount of RDF burned was limited to approximately 17% in terms of the total heat produced. This was because RDF, due to its lower heating value, cannot sustain sufficient temperatures to maintain required boiler efficiency and steam quality. Also, RDF requires a longer residence time in the boiler for complete combustion, and this places another physical restriction on the amount of RDF in the fuel mixture. Fuel oil is used sparingly, and only as an igniter to insure flame continuity during soot blowing. The large variations in fuel oil consumption noted in Table 15 were more related to operating practices than to the boiler requirements.

The means and standard deviations for coal consumption follow those of the gross electrical output. This indicates that coal consumption is closely related to electrical output, as expected. However, these daily averages mask out one important effect. The amount of coal burned depends on whether there is RDF in the mixture or not. All other things being equal, the flow of coal will always go up or down, depending on whether RDF is being removed or introduced into the mixture, respectively.

Data for the steam cycle in the boiler are also listed in Table 15 on an average basis. Examination of the data on a daily basis indicated that the steam and feedwater flow rates fluctuate in a daily cycle, with means and standard deviations following the gross electrical output. However, the values for steam temperature and pressure remain fairly constant. The feedwater temperature also varied. It was higher on days of high electricity production, and lower on days of low production.

The induced and forced draft fan measurements listed in Table 15 are of limited significance, since they did not respond to increases in production with greater airflows and correspondingly greater current consumption. The furnace draft data indicated little or no correspondence to any of the other measured data. Most of the flue gas and ESP inlet temperature readings were incomplete as they did not cover the entire 24-hr day. Most of this information was recorded during peak operation, and may therefore be considered representative for peak operation conditions. Both the flue gas and ESP inlet temperatures decreased during off-peak periods.

The continuous supply of RDF to the boiler during the test was found to be unreliable. The RDF conveyors which feed Unit No. 7 were prone to jamming and required frequent maintenance. Often the RDF supply ran out because the solid waste recovery plant was experiencing mechanical problems, or had run out of refuse to process. The durations of RDF-firing during the flue gas sampling periods are shown in Table 16 along with the mean coal feed rates.

TABLE 16. FUEL COMBUSTION DURING FLUE GAS SAMPLING

Date	Test period	Mean coal feed rate (1,000 lb/hr)	RDF feed period	Mean RDF density (lb/ft^3)
3/2/80	1120-2000	34.9	None	-
3/3/80	0920-1855	36.2	1100-1530	5
3/4/80	0900-1800	34.3	Entire run	4.7
3/5/80	0900-1820	35.5	1020-finish	5
3/6/80	0840-2140	35.4	0900-finish	4.3
3/7/80	0850-2220	35.7	1230-finish	4
3/8/80	0840-2215	32.1	0900-finish	3.7
3/9/80	0830-2211	25.2	None	-
3/10/80	0810-1733	36.3	1512-finish	4
3/11/80	0825-2235	33.8	Entire run	4
3/12/80	0910-1315	35.1	Entire run	4.3
3/13/80	0835-2147	38.6	1608-finish	4.3
3/14/80	0840-2255	34.4	Entire	4.5
3/15/80	0905-2206	23.0	None	-
3/17/80	0849-2225	35.1	1010-1105 1340-finish	NA[a]
3/18/80	0900-2325	33.5	Entire run	3.7
3/19/80	0843-2407	32.6	Start-1310 1610-finish	4
3/20/80	0905-1625	33.3	1100-1135	3.5
3/22/80	0947-1412	33.2	Start-1212	
3/23/80	0927-1410	21.4	None	-
3/24/80	1110-1547	33.1	Entire run	4
3/25/80	1120-1546	33.8	Entire run	3.8
3/26/80	0922-1406	35.1	Start-1330	3.3

a NA = not available.

Out of 23 days of sampling, RDF was burned during the entire test run for only 7 days. On 12 days RDF was burned part of the time, and on 4 days it was not burned during the flue gas sampling.

Routine activities such as ash removal and soot blowing were performed at times designated in the test plan. RDF was observed to have a substantially higher ash content than coal, and this characteristic was reflected by longer ash removal periods, and more periodic soot blowing. Both activities decreased substantially when RDF was not being burned.

Table 17 contains information on daily production and consumption at the Ames Municipal Power Plant, Unit No. 7 recorded by the power plant operators

TABLE 17. DAILY PRODUCTION AND CONSUMPTION AT AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Date	Power production (kwh)		Thermal energy[a] (Btu/kwh)		Steam production (lb/kwh)	Fuel consumption				Sluice water for bottom and fly ash Removal (gal.)	Water input to evaporator (gal.)
	gross	net	gross	net		Iowa coal (lbs)	Colorado coal (lbs)	RDF[b] (lbs)	Oil (gal.)		
3/2/80	681,000	623,902	11,186	12,210	9.57	339,988	432,712	0	60	250,000	8,300
3/3/80	709,000	648,682	11,296	12,346	9.59	418,330	342,270	113,000	160	340,000	9,000
3/4/80	761,000	700,072	11,396	12,388	9.53	412,290	351,210	226,800	70	320,000	2,200
3/5/80	759,000	698,461	11,697	12,711	9.73	434.538	370.162	192,375	60	380,000	6,800
3/6/80	740,000	679,858	11,693	12,728	9.50	432,096	339,504	213,200	90	450,000	9,200
3/7/80	735,000	674,470	11,652	12,697	9.64	427,127	378,773	130,800	100	320,000	2,500
3/8/80	648,000	590,057	11,602	12,742	9.54	358,286	317,720	168,460	130	360,000	1,120
3/9/80	494,000	443,496	11,524	12,836	9.47	301,888	267,712	26,000	150	314,908	8,500
3/10/80	693,000	635,037	10,955	11,985	9.54	486,980	262,220	81,200	100	386,716	6,300
3/11/80	739,000	678,629	11,440	12,458	9.57	334,328	392,472	229,600	270	403,172	5,800
3/12/80	750,000	688,456	11,348	12,362	9.62	408,980	334,620	229,075	290	413,644	3,500
3/13/80	742,000	681,889	11,544	12,562	9.68	432,270	368,230	144,075	50	422,620	9,100
3/14/80	729,000	668,119	11,537	12,588	9.51	412,440	324,060	230,400	90	418,132	0
3/15/80	508,000	457,939	11,434	12,684	9.50	322,448	253,352	22,050	910	335,104	5,700
3/17/80	699,000	639,942	11,170	12,201	9.59	412,335	337,365	97,650	70	396,000	11,100
3/18/80	759,000	696,494	10,855	11,829	9.52	417,010	341,190	154,874	60	473,000	15,200
3/19/80	748,000	682,596	10,794	11,829	9.51	414,315	338,985	134,816	100	477,000	6,000
3/20/80	753,500	689,205	11,368	12,388	9.56	445.392	379,408	63,700	490	320,000	7,300
3/22/80	706,000	647,644	11,077	12,075	9.55	410,520	335,880	92,000	640	250,000	5,400
3/23/80	426,000	382,263	11,311	12,605	9.49	269,610	220,590	0	800	180,000	16,600
3/24/80	710,000	650,039	10,841	11,841	9.61	629,920	157,480	51,600	490	300,000	4,500
3/25/80	700,000	642,011	11,080	12,081	9.52	610,880	152,720	93,000	680	430,000	4,000
3/26/80	726,000	664,973	10,949	11,954	9.60	612,960	153,240	134,970	40	540,000	18,500

a This value is derived from the average Btu content of each fuel.

b This is only a rough measure of RDF weight.

on a daily basis. The total gross and net power production was recorded directly from meters inside the plant. The total steam produced divided by the gross power production gave a good indication of boiler efficiency. Separate meters were used for measuring the water used for ash removal and the total input to the evaporators. The days of highest sluice water use corresponded with days of prolonged use of RDF in the fuel mixture. The evaporators eventually feed into the working fluid cycle of the boiler, and gave a fair indication of make-up water required, except that there was a water reclamation system attached to the boiler. Hence, these values indicated new input to the system, but did not account for total make-up water requirements.

Most of the fuel types were very accurately measured. Coal was measured through a weight integrating system, and fuel oil was similarly measured through a volume integrating system. However, no accurate measurement of the RDF was possible. The values listed were derived from volumetric readings and a very rough measurement of the RDF density, taken once every shift. Although rough estimates of the RDF content were made, there was no effective means for obtaining a representative sample of the refuse mixture. The variability of the RDF in the total pulverized mixture is reflected in the results for TOCl and inputs and emissions of cadmium from this plant.

The BTU contribution of each fuel was then calculated by doing calorimetric analyses. This was done periodically, and the values used for the duration of this test program are given in Table 18. By summing the Btu contribution of each fuel, a value for total heat production was found. This value was then divided by either the gross or net electricity production to express thermal energy as it related to the power production of the day.

CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

The field test activity took place from April 30, 1980 to May 23, 1980. All required tests were completed and all recovered samples were sent to GSRI for analysis. A summary of the reduced flue gas data (inlet and outlet) on a daily basis as calculated from the field data sheets is presented in Table 19. Events that may influence the quality of the tests are also noted on this table.

The process parameters considered to be important to the operation of Boiler No. 2 included the steam flow rate, steam pressure, feedwater flow rate, feedwater temperature, combustion air flow rate, combustion air temperature, % oxygen, I.D. fan pressure, F.D. fan pressure, furnace draft and furnace temperature. Most of this data was available from instrumentation in the control room. Table 20 summarizes this plant process data in terms of the average values of the typical sampling date operations. This data is presented in terms of 24-hr plant operation and the flue gas test period durations. Although there are some slight variations, the values are readily comparable for the two time intervals. A comparison of the daily process data with the average of the data collected indicates that the Chicago Northwest Incineration facility operated in essentially the same mode 24 hr a day, 7 days a week. Although major changes in steam production were noted to occur over short time intervals (less than 1 hr) no significant variation in steam production occurred day to day indicating a rather consistent fuel feed rates during the duration of the tests.

TABLE 18. HEAT CONTENT OF FUELS USED AT THE AMES MUNICIPAL POWER PLANT DURING SAMPLING PERIOD

	Heat content for each fuel type			
Duration of test	Iowa coal (Btu/lb)	Colorado coal (Btu/lb)	RDF (Btu/lb)	Fuel oil (Btu/gal.)
3/2/80 thru 3/16/80	8,946	10,556	5,587	138,603
3/17/80 thru 3/26/80	9,035	10,298	6,128	138,603

TABLE 19. DAILY DATA SUMMARIES FOR FLUE GAS MEASUREMENTS, CHICAGO NORTHWEST INCINERATOR, BOILER NO. 2

Date (1980)	Test No.	Sampling location		Sample volume DSCF	Sample volume DSCM	Gas composition[a] O_2 %	CO_2 %	CO ppm	THC ppm	Stack temperature °F	Molecular weight	Moisture %	Velocity ft/sec	Gas flow[b] ACFM	Gas flow[b] DSCFM	Gas flow[b] DSCMM	Isokinetic rate %
5-4	1	Inlet	North[c]	256.84	7.27	11.2	7.4	172[d]	< 2	459.47	28.26	11.56	20.17	111,400	56,500	1,600	90.82
			South[e]	135.20	3.83	11.2	7.4	172	< 2	444.88	28.52	9.57	21.27				79.24
		Outlet	North	317.86	9.00	11.3	7.7	156	< 2	432.76	28.33	11.56	36.40	102,200	51,830	1,468	94.61
			South	324.14	9.20	11.3	7.7	156	< 2	451.27	28.41	10.87	39.33				97.96
5-6	2	Inlet	North	408.46	11.57	9.6	10.1	159	< 2	459.04	28.53	12.24	20.62	104,300	51,300	1,453	96.25
			South[f]	379.18	10.74	9.6	10.1	159	< 2	445.78	28.56	12.03	18.42				98.32
		Outlet	North	418.43	11.85	10.4	9.5	171	< 2	442.00	28.45	12.47	38.21	106,400	55,310	1,566	98.85
			South[g]	457.89	12.97	10.4	9.5	171	< 2	451.04	29.58	2.95	40.60				93.23
5-7	3	Inlet	North	324.36	9.19	9.4	9.8	185	< 2	445.55	28.34	13.43	19.90	110,900	54,930	1,555	98.17
			South	400.66	11.34	9.4	9.8	185	< 2	431.46	28.36	13.26	21.23				97.71
		Outlet	North	403.32	11.42	9.4	9.7	189	< 2	459.04	28.39	12.86	36.70	102,000	49,780	1,410	100.75
			South	407.07	11.53	9.4	9.7	189	< 2	457.78	28.41	12.75	38.87				96.29
5-8	4	Inlet	North	331.52	9.39	9.9	9.5	142	< 2	445.36	28.57	11.27	19.34	105,600	52,770	1,494	100.22
			South	370.83	10.50	9.9	9.5	142	< 2	460.60	28.50	11.85	19.96				97.28
		Outlet	North[h]	427.50	12.11	10.4	8.9	169	< 2	454.20	28.82	8.60	38.39	108,100	54,430	1,541	96.59
			South	457.50	12.96	10.4	8.9	169	< 2	464.32	28.47	11.60	41.69				100.04
5-9	5	Inlet	North[i]	342.70	9.77	7.9	10.5	61	< 2	423.77	28.30	14.14	17.71	93,900	45,870	1,299	99.85
			South[j]	367.81	10.42	7.9	10.5	61	< 2	460.80	28.20	14.94	17.31				101.90
		Outlet	North	371.55	10.52	8.1	10.7	59	< 2	449.64	28.17	15.46	32.99	88,400	42,770	1,211	105.57
			South	383.75	10.87	8.1	10.7	59	< 2	437.76	28.24	14.89	32.48				107.99
5-10	6	Inlet	North	320.56	9.08	8.8	10.3	1	< 2	452.59	28.37	13.62	18.12	96,530	46,250	1,310	108.82
			South	347.61	9.84	8.8	10.3	1	< 2	457.63	28.34	13.83	17.86				105.61
		Outlet	North[k]	367.97	10.42	9.4	9.7	1	< 2	448.92	28.50	11.94	35.43	101,200	49,320	1,397	98.61
			South	412.06	11.67	9.4	9.7	1	< 2	452.28	28.33	13.40	39.50				96.51
5-11	7	Inlet	North	344.80	9.76	9.8	9.0	1	< 2	463.29	28.19	13.86	19.12	101.000	48,280	1,367	100.85
			South	378.50	10.72	9.8	9.0	1	< 2	462.48	28.15	14.24	18.51				100.82
		Outlet	North[m]	299.62	8.49	9.8	9.5	1	< 2	462.53	28.37	12.91	38.99	103,900	50,470	1,429	99.20
			South[m]	459.63	13.02	9.8	9.5	1	< 2	447.47	28.30	13.52	38.13				102.22
5-12	8	Inlet	North	316.55	8.96	8.7	9.7	1	< 2	456.24	28.40	12.57	17.58	98,830	47,970	1,358	98.95
			South	373.03	10.56	8.7	9.7	1	< 2	468.33	28.38	12.79	19.11				94.93
		Outlet	North	376.48	10.66	10.4	9.0	1	< 2	442.84	28.41	12.21	36.73	102,500	50,800	1,438	102.67
			South	391.17	11.08	10.4	9.0	1	< 2	452.88	28.42	12.08	39.17				100.42
5-13	9	Inlet	North	308.73	8.74	9.7	9.6	1	< 2	465.61	28.19	14.57	16.42	92,240	43,330	1,227	105.23
			South	364.16	10.31	9.7	9.6	1	< 2	468.65	28.19	14.52	17.82				102.11
		Outlet	North	366.28	10.37	9.1	9.8	1	< 2	457.16	28.25	14.10	36.85	102,900	49,060	1,389	104.01
			South	388.73	11.01	9.1	9.8	1	< 2	453.52	28.20	14.54	39.39				102.82
5-15	10	Inlet	North	338.45	9.59	10.2	9.4	111[o]	< 2	465.43	28.29	13.60	18.05	95,870	46,760	1,324	102.87
			South	376.86	10.67	10.2	9.4	111	< 2	458.88	28.27	13.75	17.67				102.67
		Outlet	North[n]	377.44	10.69	9.6	9.7	98	< 2	459.56	28.88	8.89	35.47	99,850	49,810	1,410	102.40
			South	396.28	11.22	9.6	9.7	98	< 2	463.68	28.24	14.22	38.49				106.30

(continued)

TABLE 19 (continued)

Date (1980)	Test No.	Sampling location		Sample volume DSCF	Sample volume DSCM	Gas composition[a] O_2 %	CO_2 %	CO ppm	THC ppm	Stack temperature °F	Molecular weight	Moisture %	Velocity ft/sec	Gas flow[b] ACFM	DSCFM	DSCMM	Isokinetic rate %
5-16	11	Inlet	North	353.83	10.02	11.1	8.5	88[o]	< 2	465.32	28.49	11.15	18.79	99,300	49,200	1,395	101.23
			South	357.30	10.12	11.1	8.5	88	< 2	467.67	28.42	11.69	18.22				93.06
		Outlet	North	404.61	11.46	11.8	7.9	98	< 2	455.72	28.35	11.79	38.83	117,500	58,310	1,651	104.09
			South	416.58	11.80	11.8	7.9	98	< 2	460.24	28.38	11.59	40.83				101.62
5-17	12	Inlet[p]	North	324.92	9.20	10.3	10.0	80	< 2	474.80	28.27	13.47	17.25	91,430	43,540	1,233	97.56
			South	331.75	9.40	10.3	10.0	80	< 2	475.00	28.37	13.70	16.85				102.20
		Outlet[p]		218.81	6.20	10.7	9.0	84	< 2	451.00	28.16	14.38	39.27	106,000	51,350	1,454	103.01
5-18	13	Inlet	North South	q													
		Outlet		219.36	6.20	10.7	9.2	102	r	463.00	28.25	13.91	44.37	119,800	57,360	1,624	92.45
5-19	14	Inlet	North South	q													
		Outlet		240.61	6.81	12.7	7.2	304	r	465.60	28.36	11.65	44.53	120,200	59,140	1,675	98.36

a Average during test period.

b Sum of the North and South train measurements.

c Test was run for 350 min. Test was discontinued because of unsuccessful leak checks after filter replacement.

d High due to excessive instrument drift.

e Test ran for only 193 min due to plant shut down because of a boiler leak.

f Only 21 of the required 24 points were traversed.

g Test quality was poor due to crack in the probe.

h Low moisture obtained because of cracked probe.

i Sampling time increased from 20 to 25 min per point after 180 min. Test quality was good.

j Sampling time increased from 20 to 25 min per point after 267 min. Test quality was good.

k Test was halted one point from completion due to stormy water. Test quality was good.

l Analyzer taken off line (see d).

m Due to excessive leak rate in the north tracer, 60% of the sample was collected with the south tracer, 40% with the north.

n Probe was found with a cracked tip. Based on 8.9% moisture versus 12% moisture for the other tests, it was determined that only the last 10 points were traversed with the broken probe. Test quality was fair.

o Results ± 10% due to drift.

p Inlet QA test, outlet 1st day cadmium test.

q Inlet sample not required for cadmium test.

r THC data not required for cadmium test.

TABLE 20. MEANS OF THE MEANS FOR PROCESS DATA, ALL TEST DAYS, CHICAGO NW INCINERATOR, BOILER NO. 2[a]

Parameter	24-hr process data Mean	24-hr process data Standard deviation	Flue gas test duration process data Mean	Flue gas test duration process data Standard deviation
Steam flow rate (lbs/hr)				
Disc recorder	99,000	4,500	100,000	8,100
Chart recorder	103,000	4,500	104,000	8,300
Digital integrator	99,000	3,600	100,000	10,300
Steam pressure (psig)	282	4	287	2
Feedwater flow rate (lbs/hr)				
Chart recorder	99,000	4,800	101,000	8,400
Digital integrator	97,000	5,400	100,000	11,000
Feedwater temperature (°F)	221	1	221	1
Combustion air flow rate (ft^3/hr)				
Chart recorder	79,000	2,000	78,000	2,700
Digital integrator	72,000	2,600	70,000	2,200
Combustion air temperature (°F)	663	21	673	23
I.D. fans pressure (inches H_2O)	2.6	0.2	2.5	0.3
F.D. fans pressure (inches H_2O)	14.1	0.4	14.1	0.6
Furnace draft (inches H_2O)	0.23	0.06	0.22	0.8
Furnace temperature (°F)	1,160	42	1,198	67

a From Appendix B.

Additional information collected for daily process tables included the times of soot blowing, fuel input to Boiler No. 2, down time on Boiler No. 2, daily barometric pressure and miscellaneous comments concerning the boiler operation. Soot blowing was to follow a set schedule of three times per day, although deviations from this schedule were observed. Barometric pressure was obtained once per day from nearby Midway airport and deviations from typical plant operation were noted from the operator's log book.

The measurement of fuel input posed a somewhat more difficult problem. All refuse and residue hauling trucks entering and leaving the incinerator plant were carefully weighed. This facilitated the accurate characterization of overall inputs and outputs. However, there was no accurate way of proportioning these materials between specific boilers for a given period of time. Attempts to determine the fuel burned or ash discharged from Boiler No. 2 were approximations.

Chicago Northwest Incinerator maintains inventory sheets listing inputs and outputs from the facility on a weekly basis. Relevant data from these sheets are reproduced in Table 21. The weight of refuse received was measured on scales before and after the refuse trucks released their loads. The volume of refuse received was determined by multiplying the number of truck loads by the volume of each truck (19.5 cubic yards). Density of the refuse was estimated using these two measurements, and is therefore the density of refuse inside the trucks. In order to quantify the amount of refuse burned, the number of loads, or charges, handled by the grab bucket cranes were noted for each boiler. The total number of charges to Boiler No. 2 for daily operations are given in Table 22.

To approximate the amount of refuse burned in Boiler No. 2, it was necessary to determine an average weight per charge. When refuse trucks enter the plant, they discharge their contents into a large storage pit. Although the weight of refuse added to the pit is well characterized for each weekly period, the carry-over of material from week to week cannot be accurately measured. Furthermore, this carry-over is quite variable over the length of time being considered. It is necessary to quantify the carry-over in terms of weight, so that the total weight of refuse burned, and hence, the average weight per charge, can be approximated.

The calculation of the average weight per charge involves using visual measurements of the pit volume taken at the end of each week. This "pit estimate" can then be used in association with the density of the incoming garbage to approximate the weight of refuse in the pit. The average weight per charge can be determined by the following equation:

$$\begin{array}{l}\text{Average wt} \\ \text{per charge}\end{array} = \frac{(\text{pit estimate for previous week} - \text{pit estimate} + \text{refuse delivered})}{\text{total number of charges}}$$

All terms in parenthesis must be expressed as weights. This method, however, has a drawback in that the density in the pit is probably not the same as the density inside the refuse trucks, since the refuse inside the trucks is compacted and is liable to expand somewhat as the trucks are unloaded.

TABLE 21. WEEKLY INVENTORIES OF REFUSE AND RESIDUE AT THE CHICAGO NW INCINERATOR (ALL BOILERS)

	4/28/80 to 5/4/80	5/5/80 to 5/11/80	5/12/80 to 5/18/80	5/19/80 to 5/25/80
Refuse received				
By weight (tons)	6,747	9,152	7,902	8,720
By volume (cu yd)	24,490	29,618	26,561	28,778
Density (lbs/yd^3)	551	618	595	606
Storage pit condition				
At beginning of week (% full)	84	65	61	42
At end of week (% full)	65	61	42	42
Refuse consumed				
No. charges burned	5,205	5,710	5,952	4,714
Average weight per charge (lbs)	2,771	3,240	2,812	3,700
Total weight (tons)	7,212	9,250	8,367	8,720
Total volume (cu yd)	28,562	36,634	33,138	34,535
Residue				
Fine ash fraction (tons)	2,511	2,500	1,815	2,904
Fine ash fraction (cu yd)	3,100	3,086	2,240	3,585
Metal fraction (tons)	949	750	1,514	629
Metal fraction (cu yd)	5,423	4,286	18,651	3,594
Total ash (tons)	3,460	3,250	3,329	3,533
Total ash (cu yd)	8,523	7,372	10,891	7,179
Volume reduction thru incineration	70%	80%	67%	79%
Weight reduction thru incineration	52%	65%	60%	60%

TABLE 22. CHARGES FED TO BOILER NO. 2 ON A SHIFT BASIS
CHICAGO NORTHWEST INCINERATION FACILITY

Date, shift		No. of charges	Date, shift		No. of charges	Date, shift		No. of charges	Date, shift		No. of charges
4-28,	2nd	98	5-5,	2nd	-	5-12,	2nd	99	5-19,	2nd	110
	3rd	99		3rd	-		3rd	99		3rd	105
4-29,	1st	100	5-6,	1st	-	5-13,	1st	100	5-20,	1st	104
	2nd	94		2nd	68		2nd	100		2nd	118
	3rd	101		3rd	112		3rd	60		3rd	110
4-30,	1st	90	5-7,	1st	99	5-14,	1st	-	5-21,	1st	100
	2nd	94		2nd	84		2nd	-		2nd	106
	3rd	101		3rd	100		3rd	96		3rd	90
5-1,	1st	94	5-8,	1st	81	5-15,	1st	104	5-22,	1st	80
	2nd	49		2nd	101		2nd	106		2nd	105
	3rd	98		3rd	100		3rd	108		3rd	100
5-2,	1st	100	5-9,	1st	100	5-16,	1st	106	5-23,	1st	107
	2nd	98		2nd	98		2nd	97		2nd	107
	3rd	101		3rd	100		3rd	110		3rd	102
5-3,	1st	100	5-10,	1st	99	5-17,	1st	112	5-24,	1st	98
	2nd	102		2nd	101		2nd	97		2nd	105
	3rd	99		3rd	100		3rd	114		3rd	94
5-4,	1st	97	5-11,	1st	102	5-18,	1st	108	5-25,	1st	101
	2nd	96		2nd	101		2nd	104		2nd	105
	3rd	12		3rd	105		3rd	118		3rd	107
5-5,	1st	-	5-12,	1st	103	5-19,	1st	105	5-26,	1st	105
Total for week		1,823			1,754			1,943			2,159

It seems likely that the level of compression would have a more pronounced effect upon the refuse density than the actual characteristics of the refuse. Since the compaction inside the pit is always similar, one would also expect the density in the pit to be reasonably constant. The plant personnel indicated that the typical refuse density was 505 lb/cu yd. Therefore, this value can be used as an assumed density, and the pit estimates used in the equation:

$$\text{Volume of refuse in pit} = \frac{\text{pit estimate (\% of total volume) x total pit volume}}{100}$$

total pit volume = 9,700 cu yd

Weight of refuse in pit = volume of refuse in pit x refuse density in pit

assumed refuse density = 505 lb/cu yd

Weight of refuse incinerated per week = (weight of refuse in pit at beginning of week - weight of refuse in pit at end of week + weight of refuse delivered)

$$\text{Average weight per charge} = \frac{\text{total weight of refuse incinerated}}{\text{total number of charges}}$$

$$\text{Volume of refuse incinerated} = \frac{\text{weight of refuse incinerated}}{\text{assumed refuse density}}$$

The amounts of fine ash and metal fractions produced by the incinerator during the test period are listed in Table 21. It should be noted that these are the amounts leaving the plant during this time period, and are not necessarily the same as the ash being produced during this period. Since no account has been taken of any carry-over from week to week, it can only be assumed the carry-over is similar each week. In order to obtain total ash, the metal and fine ash fractions were summed together. The ash volumes were calculated using the following densities:

Density of fine ash fraction = 1,620 lb/cu yd (960 kg/m^3)
Density of metal fraction = 350 lb/cu yd (210 kg/m^3)

These values were based on previous analyses done by the plant, and have been assumed to be typical. Since all of the combined ash was subjected to a water quench, these weights incorporate a rather large moisture content. However, no better characterization was available. The volume and weight reductions achieved through incineration have been calculated as an indication of how efficiently the boilers were operating.

Due to the heterogeneous nature of the refuse used to fuel this plant, it was very difficult to obtain representative samples for laboratory analyses for organic compounds and cadmium. The previous discussion of the approximation of refuse burned in Unit No. 2 reflects an additional problem in previding accurate information for the levels of the analytes introduced as inputs to this combustion source. Both the variabilities of TOCl and cadmium and the agreement of cadmium between the inputs and emissions from the plant were highly affected by the difficulty of obtaining representative refuse samples.

SECTION 8

ANALYTICAL RESULTS

AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Organics

The results of TOCl determinations in flue gas inlet and outlet samples from the Ames plant are shown in Tables 23 and 24, respectively, along with the recoveries observed for the surrogate spiking compounds. The results for plant background air particulates, ESP ash, bottom ash, coal, RDF, bottom ash quench influent water (cooling tower blowdown), bottom ash quench overflow water, and untreated well water (plant intake water) are shown in Tables 25 to 32. These results, as well as all other results in this report, are shown uncorrected for surrogate recoveries. The coal extracts apparently contained very high levels of hydrocarbons. Hence, the Hall detector used for TOCl assays required cleaning after only one to two analyses. Hence, TOCl assays were completed on only six coal extracts. Organic chlorine was not detected by the TOCl procedure in any of the field blanks, method blanks, or flue gas first impinger extracts.

In general, the surrogate recoveries were good in all samples. The recoveries for d_8-naphthalene (typically 50-80%) were generally lower than for d_{12}-chrysene (typically 70-100%). This is likely due to the much higher volatility of naphthalene compared to chrysene. Hence, naphthalene losses may be partially attributed to volatility losses during extract concentration.

The results of determinations of PAH compounds and additional compounds identified in the composite extracts are shown in Table 33. In addition to PAH compounds, chlorinated benzenes and phenols were identified in some samples. Notably, phenol was detected at parts-per-million concentrations in the coal extracts. Phthalate esters were also identified in RDF and ash samples. As anticipated, phthalate levels were high in the RDF extracts. Low levels of phthalate esters were also identified in the composite flue gas extracts, although the levels were similar to those observed in the flue gas train blanks. The levels of phthalate esters in the train blank ranged from 0.3 to 4 µg/dscm.

The results of HRGC/MS-SIM analysis of the composite Ames flue gas outlet extracts for PCBs are shown in Table 34. These results are similar to those obtained by Richard and Junk[7] for the Ames Unit No. 7. The primary chlorobiphenyl compounds identified were tetra- through hexachloro-substituted.

TABLE 23. TOCl AND SURROGATE RECOVERY RESULTS FOR THE AMES FLUE GAS INLET SAMPLES

Test day	Date	Sample volume (dscm)	TOCl Mass (ng)	TOCl Conc. (ng/dscm)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
1	3-2	13.23	3,210	243	0	85
2	3-3	17.41	20,000	1,150	63, 85	100, 100
3	3-4	12.38	9,480	766	61, 82	98, 79
4	3-5	14.27	6,480	454	31	33
5	3-6	19.56	18,600	951	57	58
6	3-7	20.79	8,560	412	51	82
7	3-8	19.40	7,110	367	43	60
8	3-9	17.87	7,350	411	44, 48	76, 74
9	3-10	9.18	7,650	833	55	81
10	3-11	22.01	12,400	562	42	63
11	3-12	Test scrubbed				
12	3-13	20.39	11,600	568	59	76
13	3-14	20.57	11,500	559	54	81
14	3-15	15.43	6,320	410	49	87

(continued)

TABLE 23 (concluded)

Test day	Date	Sample volume (dscm)	TOCl Mass (ng)	TOCl Conc. (ng/dscm)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
15	3-17	21.25	8,170	394	120	86
16	3-18	20.97	22,600	1,080	45	39
17	3-19	20.34	6,390	314	63	60
18	3-20	20.27	13,100	647	54	52
19	3-22	20.16	6,330	314	103	87
20	3-23	18.90	4,780	253	50	55

TABLE 24. TOCl RESULTS AND SURROGATE RECOVERIES FOR THE AMES FLUE GAS OUTLET SAMPLES

Test day	Date	Sample volume (dscm)	TOCl Mass (ng)	TOCl Conc. (ng/dscm)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
1	3-2	12.94	2,020	156	53	92
2	3-3	17.89	21,600	1,210	60	78
3-11[a]						
12	3-13	14.85	4,920	332	59	98
13	3-14	20.37	34,200	1,680	64	76
14	3-15	17.73	4,230	238	24	64
15	3-17	22.62	21,500	948	43	85
16	3-18	21.12	18,100	855	43	84
17	3-19	20.81	21,800	1,050	49	105
18	3-20	21.09	4,330	205	46	89
19	3-22	22.75	2,830	124	35	77
20	3-23	18.71	2,930	157	41	98

a No flue gas outlet samples collected due to severe weather.

TABLE 25. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES PLANT BACKGROUND AIR PARTICULATE SAMPLES

Test Day	Date	Volume[a] (m^3)	TOCl (ng)	TOCl (ng/m^3)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
1	3-2	500	2,930	5.9	23	85
2	3-3	540	3,920	7.3	3	110
3	3-4	510	3,150	6.2	24	100
4	3-5	550	3,190	5.8	26	96
5	3-6	800	4,940	6.2	41	100
6	3-7	700	3,240	4.6	56	110
7	3-8	600	3,160	5.3	24	73
8	3-9	870	3,460	4.0	45	88
9	3-10	750	3,750	5.0	39	93
10	3-11	830	5,110	6.2	36	93
11	3-12	600	4,180	7.0	48	140
12	3-13	960	3,260	3.4	59	130
13	3-14	930	2,980	3.2	59	140
14	3-15	910	4,530	5.0	32	92
15	3-17	910	3,820	4.2	80	79
16	3-18	950	5,090	5.4	68	110
17	3-19	960	6,580	6.9	65	77
18	3-20	1,110	4,620	4.2	73	89
19	3-22	840	2,690	3.2	51	120
20	3-23	1,040	1,880	1.8	73	83
	Filter Blank		4,260		95	120
	Filter Blank		2,110		45	57

a Calculated from the sampling time and the flowmeter reading on the Hi-Vol sampler.

TABLE 26. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES ESP ASH SAMPLES

Test day	Date	Time	Hopper code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
0	3-1	0300	B			
		0430	A			
		0830	B	1.8	36	100
		1230	A			
		1630	A			
		2030	B			
1	3-2	0030	B	5.9	78	140
		0430	B	6.3	38	140
		0830	A	5.8	60	87
		1230	B	0.3	91	69
		1630	B	4.5	61	73
		2030	B	5.3	73	95
2	3-3	0030	A	4.1	57	84
		0430	B			
		0830	A	2.2	59	58
		1230	A			
		1630	B	1.1	46	88
		2030	B			
3	3-4	0030	B	5.1	40	110
		0430	B	8.7	46	65
		0830	A	1.1	71	110
		1230	B	10.6	61	78
		1630	B	5.4	70	69
		2030	B	8.0	71	90
4	3-5	0030	A	2.7	52	98
		0430	B			
		0830	B	8.5	54	90
		1230	B			
		1630	B	4.4	54	71
		2030	B			
5	3-6	0030	A	3.4	1	100
		0430	B			
		0830	B	2.5	5	83
		1230	B			

(continued)

TABLE 26 (continued)

Test day	Date	Time	Hopper code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
5	3-6	1630	B	2.2	28	100
		2030	A			
6	3-7	0030	A	2.4	0	90
		0430	A			
		0830	A	3.0	60	98
		1230	A			
		1630	B	4.0	65	89
		2030	B			
7		2330	B	210	9	90
	3-8	0330	B			
		0730	A	3.7	41	100
		1130	A			
		1530	B	5.2	59	99
		1930	A			
8		2330	A	8.1	47	53
	3-9	0330	A	2.5	53	83
		0730	B	1.9	33	69
		1130	B	3.2	20	69
		1530	A	3.6	34	66
		1930	B	6.4	56	90
9		2330	B	9.8	52	110
	3-10	0330	B			
		0730	A	5.7	57	110
		1130	B			
		1530	A	2.1	35	110
		1930	A			
10		2330	A	3.0	54	120
	3-11	0330	A	3.8	1	140
		0730	B	1.9	45	110
		1130	A	0.9	1	110
		1530	A	2.9	59	110
		1930	B	3.7	8	73

(continued)

TABLE 26 (concluded)

Test day	Date	Time	Hopper code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
11		2330	A	3.2	90	130
	3-12	0330	B			
		0730	A			
		1130	B			
		1530	B			
		1915	B			
12		2330	B	2.6	0	60
	3-13	0330	B			
		0730	A	2.1	7	103
		1130	A			
		1530	B	2.1	0	100
		1930	B			
13		2330	A	2.1	9	130
	3-14	0330	A			
		0730	B	4.4	38	120
		1130	B			
		1530	B	2.6	69	120
		1930	A			
22	3-25	0001	A	1.7	71	130
		0400	B			
		0800	A			
		1200	A			
		1600	B			
		2000	A			

TABLE 27. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES BOTTOM ASH SAMPLES

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
0	3-1	0105	D			
		0530	B	30.3	65	130
		0930	D			
		1330	D			
		1730	D			
		2130	B			
1	3-2	0130	D	9.0	31	31
		0530	E	13.0	42	77
		0930	C	0.6	57	67
		1300	C	3.3	85	85
		1730	D	1.6	39	52
		2130	C	99.5	43	110
2	3-3	0130	E	0.2	75	68
		0530	C			
		0930	A	362	92	110
		1330	F			
		1730	D	11.1	30	130
		2130	B			
3	3-4	0130	D	79.0	81	69
		0535	E	251	52	21
		0930	F	114	53	79
		1300	E	26.3	41	47
		1730	A	60.0	57	84
		2130	E	52.5	47	95
4	3-5	0130	D	72.0	67	50
		0530	C			
		0930	D	22.7	72	92
		1330	B			
		1730	F	13.8	50	96
		2130	F			
5	3-6	0130	E	66.5	58	89
		0530	A			
		0930	C	55.0	68	110
		1330	B			

(continued)

TABLE 27 (continued)

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
5	3-6	1730	C	11.6	55	90
		2130	E			
6	3-7	0130	C	51.0	39	81
		0530	A			
		0930	E	34.0	19	83
		1300	F			
		1730	C	81.0	38	103
		2130	F			
7	3-8	0030	E	35.9	65	79
		0430	C			
		0830	B	4.9	63	20
		1230	C			
		1630	A	57.5	54	46
		2030	A			
8	3-9	0030	B	127	77	70
		0430	B	5.8	56	76
		0830	D	1.3	12	46
		1230	D	8.0	29	48
		1630	F	0.8	51	31
		2030	A	6.2	6	49
9	3-10	0030	E	3.6	77	63
		0430	E			
		1445	C	92.5	87	120
		1630	F			
		2030	B	16.4	11	120
10	3-11	0030	D	5.7	86	97
		0430	A	38.6	53	87
		0830	A	136	77	160
		1230	D	85.5	44	130
		1630	D	97.0	79	130
		2030	A	316	66	120

(continued)

TABLE 27 (concluded)

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
11	3-12	0030	C	57.0	61	120
		0430	D			
		0830	A			
		1230	E			
		1630	E			
		2030	A			
12	3-13	0030	A	43.3	62	100
		0430	A			
		0830	D	76.0	54	110
		1630	A	349	59	100
		2030	F			
13	3-14	0030	F	32.3	59	80
		0430	C			
		0830	B	15.8	51	96
		1230	B			
		1630	A	64.5	62	110
		2030	B			
22	3-25	0100	A	14.8	68	70
		0500	D			
		0900	B			
		1300	F			
		1700	B			
		2100	E			

a The accessible portion of the hopper was divided into six sectors which were sampled according to a randomized selection scheme.

TABLE 28. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES COAL SAMPLES

Test day	Date	Time	Feed stream code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
0	3-1	0300	A	4	92	97
		0700	A			
		1100	A			
		1500	B			
		1900	B			
		2300	B			
1	3-2	0300	B	4	97	110
		0700	B	7	110	96
		1100	A	4	87	83
		1500	B	5	92	97
		2300	A	4	61	59

a Two coal feed lines were sampled according to a randomized selection scheme.

TABLE 29. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES REFUSE - DERIVED FUEL SAMPLES

Test day	Date	Time	Food stream code[a]	TOCl (ng/g)	Surrogate recovery: d_8-Naphthalene (%)	Surrogate recovery: d_{12}-Chrysene (%)
0	3-1	0225	B	5,550	42	61
		0630	D			
		1030	D			
		1430	A			
2	3-3	1430	C	10,800	58	80
		1830	B	29,500	54	160
		2230	B			
3	3-4	0230	A	5,500	45	82
		0630	A	370	75	120
		1030	C	19,000	50	98
		1430	C	23,600	41	56
		1830	A	4,400	66	120
		2230	C	2,800	64	110
4	3-5	0230	B	480	61	140
		1030	D	5,100	76	150
		1440	D			
		1830	D	5,000	71	120
		2250	C			
5	3-6	0230	B	9,500	80	140
		0630	B			
		1030	A	13,300	62	110
		1430	C			
		1830	C	1,900	55	110
		2230	B			
6	3-7	0230	A	4,250	77	100
		1430	B	18,500	50	110
		1830	B	7,050	63	170
		2230	A			

(continued)

TABLE 29 (continued)

Test day	Date	Time	Food stream code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	d_{12}-Chrysene (%)
7	3-8	0130	B	22,000	88	98
		0930	D	4,300	68	110
		1330	D			
		1730	D	9,900	55	120
		2130	C			
8	3-9	0130	B	5,000	71	110
9	3-10	1730	C	7,350	64	120
		2130	A	3,150	42	68
10	3-11	0130	A	4,950	73	150
		0530	C	21,100	86	130
		0930	A	23,200	68	93
		1330	A	8,600	35	120
		1730	D	9,550	64	130
		2130	A	10,300	55	69
11	3-12	0130	D	19,900	88	130
		0530	B			
		0900	D			
		1330	D			
		1730	C			
		2130	C			
12	3-13	0130	D	10,900	66	84
		0530	D			
		1730	D	8,200	91	98
		2130	C			
13	3-14	0130	B	16,500	77	150
		0530	C			
		0930	B	4,300	57	84
		1330	C			
		1730	A	46,300	84	98
		2130	C			

(continued)

TABLE 29 (concluded)

Test day	Date	Time	Food stream code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
22	3-25	1000	A	13,100	83	130
		1400	B			
		1800	C			
		2200	D			

a Four RDF feed lines were sampled according to a randomized selection scheme.

TABLE 30. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES BOTTOM ASH HOPPER QUENCH WATER INFLUENT SAMPLES

Test day	Date	Time	TOCl (ng/ℓ)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
1	3-2	2400	239	47	87
3	3-4	0400	271	51	120
5	3-6	1400	441	80	100
8	3-9	2100	339	82	100
10	3-11	0800	369	89	130
13	3-14	0300	576	64	130

TABLE 31. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES BOTTOM ASH HOPPER QUENCH OVERFLOW WATER SAMPLES

				Surrogate recovery	
Test day	Date	Time	TOCl (ng/l)	d_8-Naphthalene (%)	d_{12}-Chrysene (%)
0	3-1	0100 0500 0900 1300 1700 2100	90	ND[a,b]	72
1	3-2	0100	698	47	80
		0500	656	25	82
		0900	680	44	120
		1300	494	ND[b]	56
		1700	626	35	97
		2100	528	28	92
2	3-3	0100 0500	518	19[b]	79
		0900 1300	524	50	89
		1700 2100	706	64	76
3	3-4	0100	1,180	30	54
		0500	488	57	66
		0900	558	51	50
		1255	274	37	22
		1700	294	ND[b]	78
		2100	678	28	96
4	3-5	0100 0500	825	37	98
		0900 1300	889	49	110
		1700 2100	691	38	94
5	3-6	0100 0500	301	ND	24
		0900 1300	427	ND	55

(continued)

TABLE 31 (continued)

Test day	Date	Time	TOCl (ng/l)	Surrogate recovery d_8-Naphthalene (%)	d_{12}-Chrysene (%)
5	3-6	1700 2100	947	87	100
6	3-7	0100 0500	819	2	80
		0900 1300	866	80	55
		1700 2100	852	81	98
7	3-8	2400 0400	863	94	120
		0800 1200	1,100	74	94
		1600 2000 2400	1,040	71	94
8	3-9	0400	776	42	120
		0800	1,050	63	110
		1200	984	53	87
		1600	516	24	140
		2000	496	ND[b]	130
		2400	376	ND[b]	120
	3-10	0400	776[c]	0	85
		0800 1200	605	80	120
		1600 2000	795	46	100
		2400	776[c]	0	85
	3-11	0400	870	c	
		0800	806	130	120
		1200	778	110	120
		1600	864	90	86
		2000	880	17	88
		2400	728	57	83

(continued)

TABLE 31 (concluded)

Test day	Date	Time	TOCl (ng/l)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
8	3-12	0400 0800 1200 1600 2000 2400	603	2[b]	81
	3-13	0400 0800	892	e	
		1200 1600	916	44	84
		2000 2400	613	ND	57
	3-14	0400 0800	458	34	78
		1200 1600	770	42	97
		2000	1,060	42	80
	3-25	0030 0430 0830 1230 1630 2030	638	36	110

a ND = not detected.

b Extract was inadvertently evaporated to dryness.

c Samples collected at 0400 and 2400 on 3-10 were inadvertently composited.

d This sample was not spiked with the surrogate compounds.

e This extract was lost prior to analysis for surrogate recoveries.

TABLE 32. TOCl RESULTS AND SURROGATE RECOVERIES FOR AMES UNTREATED WELL WATER

Test day	Date	Time	TOCl (ng/ℓ)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
0	3-1	0200	33	ND[a]	68
5	3-6	2200	65	65	99
23	3-26	1615	62	66	97

a Extract was inadvertently evaporated to dryness.

TABLE 33. COMPOUNDS QUANTITATED IN SAMPLES FROM THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Compound	Composite day	Concentration: Coal (ng/g)	Refuse-derived fuel (ng/g)	Plant background air (ng/dscm)	Flue gas inlet (ng/dscm)	Flue gas outlet (ng/dscm)	ESP ash (ng/g)	Bottom ash (ng/g)	Bottom ash hopper quench water overflow (µg/ℓ)	Bottom ash hopper quench water overflow (µg/ℓ)	Well water[a] (µg/ℓ)
<u>Target PAH compounds</u>											
Phenanthrene	1	7,550		0.29	270	390	0.3	32			
	2	9,090	1,400	0.6	420	320		250			
	3	15,400	940	0.8	660	320	0.2	140			
	4	8,500	948	0.8	640	37	0.2	43			
	5	18,600	828	0.32	200	480	0.2	500			
Anthracene	1	1,570			59	49					
	2	1,840	296	0.17	57	77					
	3	1,260		0.16	77	78		24			
	4	2,120		0.19	89	46					
	5	4,110			100	77		130			
Fluoranthene	1	1,190		0.36	70	46		10			
	2	1,640	984	0.7	240	40		52			
	3	3,320	271	0.7	140	97		30			
	4	900	306	1.0	87	28					
	5	3,210	198	0.5	94	130		450			
Pyrene	1	1,340		0.36	220	110		9.0			
	2	1,960	552	0.7	850	96		64			
	3	3,810	436	0.7	480	250		29			
	4	1,070	282	1.1	230	66		6.0			
	5	4,040	372	0.5	330	330		420			
Chrysene	1	370		0.29	3.5		0.3				
	2	425	434	0.40	28						
	3	1,060		0.37							
	4	238		0.60	9.6						
	5	1,300		0.38	2.8	2.7		170			
Benzo[*a*]pyrene	1			0.07	21	13					
	2			0.17	64						
	3			0.11	120						
	4			0.09	19	28					
	5			0.07	63						
Indeno[1,2,3-*c*,*d*]pyrene	1										
	2										
	3										
	4			0.02							
	5										

(continued)

TABLE 33 (continued)

Compound	Composite day	Concentration: Coal (ng/g)	Refuse-derived fuel (ng/g)	Plant background air (ng/dscm)	Flue gas inlet (ng/dscm)	Flue gas outlet (ng/dscm)	ESP ash (ng/g)	Bottom ash (ng/g)	Bottom ash hopper quench water overflow (μg/ℓ)	Bottom ash hopper quench water overflow (μg/ℓ)	Well water[a] (μg/ℓ)
Benzo[g,h,i]perylene	1					3.3					
	2										
	3					22					
	4			0.09		4.6					
	5										
Additional compounds identified											
Dichlorobenzene[b]	1					3.3					0.07
	2		1,300		25			24			
	3		1,200		79		0.07				
	4		520			5					
	5		430		25						
1,2,4-Trichlorobenzene	1										
	2			0.02	99						
	3			0.01	180	110					
	4										
	5				69	85					
Hexachlorobutadiene	1										
	2										
	3			0.02	103						
	4										
	5										
Tetrachlorobenzene	1										
	2										
	3										
	4										
	5										
Pentachlorophenol	1			0.07							
	2		1,300								
	3				24						
	4										
	5		690								

(continued)

TABLE 33 (continued)

Compound	Composite day	Concentration: Coal (ng/g)	Refuse-derived fuel (ng/g)	Plant background air (ng/dscm)	Flue gas inlet (ng/dscm)	Flue gas outlet (ng/dscm)	ESP ash (ng/g)	Bottom ash (ng/g)	Bottom ash hopper quench water overflow (µg/ℓ)	Bottom ash hopper quench water overflow (µg/ℓ)	Well water[a] (µg/ℓ)
Phenol	1	10,000		3.3	4,700	6,400	220	980	0.06		
	2	12,000		1.3	4,000	7,700		1,600			
	3	2,800		0.8	13,000	3,000		1,800	0.06		
	4	23,000		1.5	5,100	6,000	190	360			
	5	29,000		1.8	9,500	6,200	380	730			
2,4-Dimethylphenol	1					1,000					
	2					1,200		27			
	3					1,300					
	4							8			
	5					2,100					
Naphthalene	1	1,400		0.28	710	650	0.17	15	0.02		
	2	1,100	36,000	0.22	1,000	550		360			
	3	1,800	2,200	0.32	620	81		110			
	4	1,800	1,500	0.28	1,800	300		29			
	5	2,700	1,500	0.13	740	850	0.18				
Fluorene	1	3,500									0.5
	2	3,100	600	0.22							
	3	5,600	450	0.32	120			14			
	4	3,300	380	0.28							
	5	7,000	320	0.13							
Benz[a]anthracene	1			0.14							
	2			0.44							
	3			0.53	7.2						
	4			0.55							
	5			0.38							
Benzofluoranthrene	1	261		0.42		6.5				0.03	0.02
	2	470		0.67	9.9	2.7					
	3	960		0.63		12					
	4	260		0.65		6.9					
	5	1,200		0.51	17						
Benzo[e]pyrene	1										
	2										
	3					29					
	4										
	5										

(continued)

TABLE 33 (continued)

Compound	Composite day	Coal (ng/g)	Refuse-derived fuel (ng/g)	Plant background air (ng/dscm)	Flue gas inlet (ng/dscm)	Flue gas outlet (ng/dscm)	ESP ash (ng/g)	Bottom ash (ng/g)	Bottom ash hopper quench water overflow (µg/ℓ)	Bottom ash hopper quench water overflow (µg/ℓ)	Well water[a] (µg/ℓ)
		Concentration									
Acenaphthene	1	650								0.07	0.7
	2	970	1,200								
	3	1,600						1.0			
	4	1,400									
	5	1,500									
Acenaphthylene	1	220						120			
	2	240			20			75			
	3	560			24			10			
	4	400						100			
	5	450						130			
Trichlorobenzene[b]	1					36					
	2					77					
	3					24					
	4										
	5										
2,4-Dichlorophenol	1								0.04		
	2										
	3										
	4										
	5										
p-Chloro-m-cresol	1										
	2										
	3										
	4										
	5										
Dimethylphthalate	1						0.30	3.0			
	2										
	3										
	4										
	5		730				0.20				
Diethylphthalate	1										
	2		9,100				11				
	3		250				0.5	37			
	4		1,400				2.0	16			
	5		11,000								

(continued)

TABLE 33 (concluded)

Compound	Composite day	Coal (ng/g)	Refuse-derived fuel (ng/g)	Plant background air (ng/dscm)	Flue gas inlet (ng/dscm)	Flue gas outlet (ng/dscm)	ESP ash (ng/g)	Bottom ash (ng/g)	Bottom ash hopper quench water overflow (µg/ℓ)	Bottom ash hopper quench water overflow (µg/ℓ)	Well water[a] (µg/ℓ)
		Concentration									
Di-n-butylphthalate	1						15	4.0			
	2		18,000				3.0	42			
	3		14,000					12			
	4		6,400				4.0	35			
	5		14,000					170			
Butylbenzylphthalate	1						6.0	32			
	2										
	3							51			
	4		49,000				6.0				
	5		22,000								
Bis(2-ethylhexyl)phthalate	1						3.0	980			
	2		350,000				2.0	1,200			
	3		44,000					480			
	4		35,000				8.0	810			
	5		22,000								

a All extracts from these samples were combined for a single composite extract.

b Specific isomer not determined.

TABLE 34. CONCENTRATIONS OF POLYCHLORINATED BIPHENYL ISOMERS IN FLUE GAS OUTLET SAMPLES FROM THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Compound identified	Composite day (Concentration, ng/dscm) 1	2	3	4	5
Trichlorobiphenyl		6.4	1.1		
Tetrachlorobiphenyl	2.2	4.5		4.1	3.8
Pentachlorobiphenyl	3.0	6.4	22.0	9.8	3.6
Hexachlorobiphenyl		4.3		11.0	10.1
Heptachlorobiphenyl		2.9			
Decachlorobiphenyl		2.9			
Total chlorobiphenyl	5.2	27.0	23.0	25.0	17.0

PCDDs and PCDFs were not detected in the Ames samples. The detection limit for PCDD and PCDF compounds in the composite flue gas extracts was 0.1 to 0.25 ng/dscm.

Cadmium

The results for cadmium analysis of samples of fly ash, bottom ash, coal and refuse-derived fuel for test days 11 to 14 and 21 to 23 are presented in Tables 35 to 39. The fly ash samples contained the highest concentrations of cadmium ranging from approximately 1.5 to 11 μg/g, while the cadmium concentration in bottom ash samples varied from approximately 0.5 to 4 μg/g. The concentration of cadmium in the coal samples was generally less than 1 μg/g while values of 1 to 5 μg/g were recorded for refuse-derived fuel. In general, the cadmium concentration for all water samples was below the detection limit (0.6 μg/liter) of the analysis method. Table 35 presents the cadmium concentrations for the flue gas outlet particulate samples for test days 21 to 23.

The concentrations of cadmium in flue gas particulates for the three test days did not vary markedly. The mean concentration was 25.3 μg/dscm with a standard deviation of 2.7 μg/dscm.

TABLE 35. CADMIUM RESULTS FOR AMES - ESP ASH SAMPLES

Test day	Date	Time	Hopper code[a]	Cadmium (μg/g)
11	3/12	2330	B	9.01
12	3/13	0330	B	10.3
	3/13	0730	A	10.8
	3/13	1130	A	8.14
	3/13	1530	B	9.89
	3/13	1930	A	3.67
	3/13	2330	A	7.36
13	3/14	0330	A	8.42
	3/14	0730	B	8.16
	3/14	1130	B	9.11
	3/14	1530	B	9.96
	3/14	1930	A	6.78
	3/14	2330	B	6.84
14	3/15	0330	A	8.47
	3/15	0730	B	4.39
	3/15	1130	B	3.43
	3/15	1530	A	8.00
	3/15	1930	B	2.88
	3/16	2330	A	5.55
	3/16	0330	B	2.35
	3/16	0730	A	1.94
	3/16	1130	B	1.65
	3/16	1530	B	2.97
	3/16	1930	B	2.93
21	3/24	0001	B	3.29
	3/24	0400	A	2.16
	3/24	0800	A	2.16
	3/24	1200	B	3.53
	3/24	1600	B	7.89
	3/24	2000	A	5.69
22	3/25	0001	A	4.53
	3/25	0400	B	5.11
	3/25	0800	A	3.36
	3/25	1200	A	8.93
	3/25	1600	B	9.70
	3/25	2000	A	6.41
23	3/26	0001	A	5.76
	3/26	0400	A	5.73
	3/26	0800	B	6.86
	3/26	1200	A	8.03
	3/26	1600	A	9.19
	3/26	2000	B	9.70

a Two hoppers were sampled according to a randomized selection scheme.

TABLE 36. CADMIUM RESULTS FOR AMES - BOTTOM ASH SAMPLES

Test day	Date	Time	Sector code[a]	Cadmium (μg/g)
12	3/13	0030	A	3.92
	3/13	0430	A	1.86
	3/13	0830	D	2.24
	3/13	1630	A	0.25
	3/13	2030	F	1.28
13	3/14	0030	F	1.66
	3/14	0430	C	3.28
	3/14	0830	B	2.96
	3/14	1230	B	1.90
	3/14	1630	A	1.90
	3/14	2030	B	1.46
14	3/15	0130	D	4.36
	3/15	0430	A	7.15
	3/15	0830	A	0.74
	3/15	1230	D	0.78
	3/15	1630	D	0.96
	3/15	2030	A	0.46
	3/16	0030	C	0.62
	3/16	0430	D	0.78
	3/16	0830	A	0.48
	3/16	1230	G	1.08
	3/16	1630	E	0.90
	3/16	2030	A	1.00
21	3/24	0100	E	1.02
	3/24	0500	C	2.82
	3/24	0900	C	0.60
	3/24	1300	C	1.64
	3/24	1700	A	0.76
	3/24	2100	A	1.34
22	3/25	0100	D	0.78
	3/25	0500	D	3.68
	3/25	0900	B	3.24
	3/25	1300	F	3.76
	3/25	1700	B	1.94
	3/25	2100	E	2.78
23	3/26	0100	B	2.00
	3/26	0500	A	2.20
	3/26	0900	C	2.28
	3/26	1300	C	2.84
	3/26	1700	B	2.02
	3/26	1200	C	2.48

a The accessible portion of the hopper was divided into six sectors which were sampled according to a randomized selection scheme.

TABLE 37. CADMIUM RESULTS FOR AMES - COAL SAMPLES

Test day	Date	Time	Feed stream code[a]	Cadmium (μg/g)
12	3/13	0600	A	0.124
	3/13	1000	B	0.024
	3/13	1400	A	0.068
	3/13	1800	B	0.116
	3/13	1800	B	4.04
13	3/14	0200	B	0.043
	3/14	0600	B	0.087
	3/14	1000	B	0.219
	3/14	1400	B	0.159
	3/14	1800	A	0.128
	3/14	2200	B	0.176
14	3/15	0200	A	0.210
	3/15	0600	A	0.293
	3/15	1000	A	0.040
	3/15	1400	A	0.153
	3/15	1800	A	0.055
	3/15	2200	B	0.075
	3/16	0200	B	0.138
	3/16	0600	B	0.027
	3/16	1000	A	0.094
	3/16	1400	B	0.099
	3/16	1800	A	0.367
	3/16	2200	B	0.141
21	3/24	0230	A	0.157
	3/24	0630	B	0.104
	3/24	1030	A	0.129
	3/24	1430	B	0.241
	3/24	1830	B	0.090
	3/24	2230	B	0.173
22	3/25	0230	B	0.122
	3/25	0630	A	0.045
	3/25	1030	B	0.079
	3/25	1430	A	0.055
	3/25	1830	A	0.084
	3/25	2230	A	0.286
23	3/26	0230	B	0.193
	3/26	0630	A	0.109
	3/26	1030	B	0.055
	3/26	1430	B	0.222
	3/26	1830	A	0.166
	3/26	2230	B	0.641

a Two coal feed lines were sampled according to a randomized selection scheme.

TABLE 38. CADMIUM RESULTS FOR AMES - REFUSE-DERIVED FUEL SAMPLES

Test day	Date	Time	Feed stream code[a]	Cadmium (μg/g)
12	3/13	0130	D	2.84
	3/13	0530	D	1.99
	3/13	1730	D	2.41
	3/13	2130	C	1.14
13	3/14	0130	B	2.31
	3/14	0530	C	2.96
	3/14	0930	B	4.85
	3/14	1330	C	2.79
	3/14	1730	A	2.37
	3/14	2130	C	3.68
14	3/15	0130	A	5.30
21	3/24	1400	C	2.63
	3/25	1000	A	3.71
	3/25	1400	B	3.72
	3/25	1800	C	2.37
	3/25	2200	D	1.73
22	3/26	0200	B	1.59
	3/26	0600	B	1.69
	3/26	1000	B	6.26
	3/26	1800	A	3.60
	3/26	2200	A	0.94

a Four RDF feed lines sampled according to a randomized selection scheme.

TABLE 39. CADMIUM RESULTS FOR AMES - FLUE GAS OUTLET PARTICULATES

Test day	Date	Volume (dscm)	Cadmium Mass (μg)	Cadmium Concentration (μg/dscm)
21	3/24	3.69	83.2	22.6
22	3/25	3.48	97.3	28.0
23	3/26	3.93	100.0	25.5

CHICAGO NORTHWEST INCINERATOR

Organics

The results of TOCl analyses of flue gas inlet and outlet samples from the Chicago incinerator are shown in Table 40 along with the corresponding surrogate recovery data. TOCl and surrogate results for plant background, air particulates, ESP ash, combined bottom ash (i.e., bottom ash plus ESP ash), refuse, and tap water (plant intake water) are shown in Tables 41 to 45. Organic chlorine was not detected by the TOCl procedure in any of the field blanks, method blanks, or flue gas first impinger extracts. These results, as well as all other results in this report, are shown uncorrected for surrogate recoveries.

In general, the surrogate recoveries were poor. As with the Ames results, d_8-naphthalene recoveries (typically 10-50%) were lower than d_{12}-chrysene recoveries (typically 30-60%). Although a portion of the apparent losses may be attributed to difficult sample matrices, the cause of consistently lower recoveries is not known.

The results of determinations of PAH compounds and additional compounds identified in the composite Chicago extracts are shown in Table 46. Composite refuse extracts were not analyzed due to extremely high levels of interfering materials and the likely nonrepresentatative nature of the refuse sample collection. A large number of chlorinated benzene and phenolic compounds were identified. Dibenzofuran was identified in the flue extracts. As noted for the Ames samples, only very low levels of phthalate esters were identified in the flue gas blank extracts.

Interestingly, the compound specific determinations compare very favorably with the TOCl results for the same extracts. Table 47 shows a comparison of the TOCl results for selected composite extracts (i.e., those in which significant levels of chlorinated compounds were identified) calculated from the TOCl concentrations in the component extracts with those calculated from the sums of chlorinted compounds identified. The percent deviation from the mean for these pairs is 14%.

The results of analysis of the composite Chicago flue gas outlet extracts for PCBs are shown in Table 48. In contrast to the results from the Ames extracts, the PCB contents of the Chicago flue gases were largely di- through pentachloro-substituted.

The results of HRGC/HRMS analyses of the composite Chicago incinerator extracts for PCDDs and PCDFs are shown in Table 49. The mean recoveries for 1,2,3,4-tetrachlorodibenzo-*p*-dioxin and octachlorodibenzo-*p*-dioxin through the extract cleanup were 60 and 25%, respectively. Although a number of PCDD and PCDF compounds were identified, trichlorodibenzofurans were found at the highest concentrations. Table 50 shows the results of specific analyses for 2,3,7,8-tetrachlorodibenzo-*p*-dioxin. This compound was detected in all three extracts, although the concentrations measured were substantially less than 1 ng/dscm. No PCDD or PCDF isomers were detected in any blank extracts.

TABLE 40. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW FLUE GAS SAMPLES

Test day	Date	Volume (dscm)	TOCl Mass (ng) Resin	TOCl Mass (ng) Particulates	TOCl Total conc. (ng/dscm)	Surrogate recovery d_8-Naphthalene (%) Resin	Surrogate recovery d_8-Naphthalene (%) Particulates	Surrogate recovery d_{12}-Chrysene (%) Resin	Surrogate recovery d_{12}-Chrysene (%) Particulates
					Flue Gas Inlet				
1	5-4	11.10	17,500	14,400	2,800	37	38	67	62
2	5-6	22.31	33,900	52,200	3,860	80	20	140	58
3	5-7	20.53	12,300	26,700	1,900	49	41	90	45
4	5-8	19.89	13,900	21,330	1,770	54	62	110	100
5	5-9	20.19	22,600	19,700	2,090	38	54	100	47
6	5-10	18.92	10,700	23,900	1,830	9	27	96	56
7	5-11	20.48	11,900	10,900	1,110	17	16	58	68
8	5-12	19.52	11,700	36,300	2,470	30	13	89	25
9	5-13	19.05	11,000	30,400	2,170	22	46	70	41
10	5-15	20.26	12,100	17,400	1,460	25	27	67	77
11	5-16	20.22	33,200	22,500	2,753	92	13	140	29
					Flue Gas Outlet				
1	5-4	18.20	16,800	3,460	1,100	7	40	58	44
2	5-6	24.82	69,100	8,780	3,140	19	19	58	40
3	5-7	22.95	32,700	7,720	1,760	0	52	0	130
4	5-8	25.07	309,000	28,600	13,500	16	16	4	23
5	5-9	21.39	32,200	12,000	2,070	5	48	35	120
6	5-10	22.09	63,200	9,940	3,310	38	27	77	50
7	5-11	21.51	47,900	6,750	2,540	44	17	99	40
8	5-12	21.74	39,400	24,000	2,920	6	36	54	70
9	5-13	21.38	19,100	7,070	1,230	64	24	120	68
10	5-15	21.91	44,500	5,940	2,300	64	28	80	66
11	5-16	23.26	30,600	4,060	1,490	18	13	82	36

TABLE 41. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW PLANT BACKGROUND AIR SAMPLES

Test day	Date	Volume[a] (m^3)	TOCl (ng)	TOCl (ng/m^3)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
2	5-6	660	1,510	2.3	58	45
3	5-7	490	1,400	2.9	67	74
4	5-8	570	1,840	3.2	46	71
5	5-9	590	1,730	3.0	23	55
6	5-10	510	< 30	< 0.1	7	1
7	5-11	590	430	0.7	55	170
8	5-12	390	< 30	< 0.1	0	0
9	5-13	580	540	0.9	34	33
10	5-15	490	890	1.8	26	28
11	5-16	710	1,240	1.7	37	44
	5-17	520	760	1.5	11	24
	5-19	320	590	1.8	2	66

a Calculated from the sampling time and the flowmeter reading on the Hi-Vol sampler.

TABLE 42. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW ESP ASH SAMPLES

Test Day	Date	Time	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
0	5-3	0200	226	41	68
		0600	203	36	63
		1000	68	0	46
		1400	89	44	80
		1800	143	45	72
		2200	54	18	35
1	5-4	0200, 0600	59	8	35
		1000, 1400	62	28	52
2	5-6	1400	62	8	24
		1800, 2200	76	7	39
3	5-7	0200, 0600	192	58	97
		1000, 1400	49	20	15
		1800, 2200	95	0	0
4	5-8	0200	370	60	83
		0600	150	28	24
		1000	15	0	12
		1400	14	18	7
		1800	23	5	18
		2200	49	44	31
5	5-9	0200	130	40	28
		0600	340	56	14
		1000	41	44	32
		1400	210	37	21
		1800	160	28	20
		2200	38	26	30
6	5-10	0400	111	37	32
		0800	84	19	35
		1200	57	9	32

(continued)

TABLE 42 (continued)

Test Day	Date	Time	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
6	5-10	1600	59	39	40
		2000	65	8	76
	5-11	0000	76	23	57
7		0400 0800	108	66	21
		1200 1600	54	30	38
	5-12	2000 0000	31	13	0
8		0400 0800	132	40	36
		1200 1600	43	36	21
	5-13	2000 0000	38	30	32
9		0400 0800	65	40	35
		1200 1600	150	30	30
	5-14	1600	76	26	26
		2000 0000	20	12	16
10	5-15	0400	220	0	48
		0800	203	52	49
		1200	70	28	25
		1600	159	23	-
		2000	< 1	0	0

(continued)

TABLE 42 (concluded)

Test Day	Date	Time	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
	5-16	0000	137	22	14
11		0400	211	24	49
		0800	78	39	59
		1200	173	50	57
		1600	15	9	17
		2000	154	0	39
12	5-17	0100, 0900, 1300, 1700, 2100	12	0	26

TABLE 43. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW COMBINED BOTTOM ASH SAMPLES

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
	5-2	2300	A	< 1	18	23
0	5-3	0300	E	< 1	39	35
		0700	E	< 1	33	26
		1100	E	< 1	18	23
		1500	A	< 1	31	20
		1900		< 1	56	21
		2300	B	< 1	52	25
1	5-4	0300 0700	A A	< 1	12	0
		1100 1500	D	< 1	34	7
2	5-6	1500	A	< 1	29	52
		1900 2300	C A	6	34	32
3	5-7	0300 0700	A E	< 1	0	26
		1100 1500	B E	6	38	58
		1900 2300	D B	3	46	52
4	5-8	0700	B	< 1	8	24
		1100	B	< 1	22	26
		1500	D	< 1	19	20
		1900	E	124	37	64
		1900	C	< 1	13	8
		2300	B	< 1	0	0
5	5-9	0300	B	7	11	5
		0700	C	76	75	9
		1100	D	5	48	11
		1500	C	3	72	78
		1900	B	< 1	47	13
		2300	A	38	85	10

(continued)

TABLE 43 (continued)

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
6	5-10	0100	A	7	13	11
		0500	E	16	42	7
		0900	B	< 1	34	8
		1300	C	< 1	41	8
		1700	E	< 1	34	11
		2100	E	49	33	12
7	5-11	0100 0500	E E	6	43	34
		0900 1300	E D	< 1	31	25
		1700 2100	B C	< 1	36	36
8	5-12	0100 0500	E B	< 1	8	13
		0900 1300	A B	28	17	25
		1700 2100	B E	18	37	26
9	5-13	0100 0500	D D	3.8	57	100
		0900 1300	C A	27	60	12
		1700	E	< 1	28	7
	5-14	1700 2100	A A	2	19	0
10	5-15	0100 0500	A E	18	34	8
		0900 1300	C C	2	35	7

(continued)

TABLE 43 (concluded)

Test day	Dae	Time	Sector code[a]	TOCl (ng/g)	Surrogate Recovery d_8-Naphthalene (%)	Surrogate Recovery d_{12}-Chrysene (%)
	5-15	1700	E	< 1	21	5
		2100	C			
11	5-16	0100	E	< 1	26	6
		0500	C	7	26	8
		0900	C	< 1	50	7
		1300	E	< 1	44	6
		1700	B	< 1	6	6
		2100	D	< 1	24	6

a The accessible portion of the bottom ash discharge hopper was divided into five sectors which were sampled according to a randomized selection scheme.

TABLE 44. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW REFUSE SAMPLES

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
0	5-3	0100	A	1,780	15	15
		0515	B	9,940	12	12
		0900	B	961	12	0
		1300	B	62	5	5
		1700	A	778	28	18
		2100	B	12,300	15	15
1	5-4	0100	A	221	0	0
		0500	B			
		0900	A	< 1	0	0
3	5-7	0900	A	14	0	0
		1300	B			
		1700	A	1,350	0	0
		2100	B			
		2110	A	< 1	25	0
4	5-8	0100	A	84	8	4
		0500	B	165	12	15
		0900	A	38	19	32
		1300	B	583	9	26
		1700	A	27	0	0
		2100	B	567	9	9
5	5-9	0100	B	1,550	36	120
		0500	A	246	5	5
		0900	A	41	0	0
		1300	B	607	14	10
		1700	B	1,670	2	0
		2100	A	273	0	0

(continued)

TABLE 44 (continued)

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
6	5-10	0300	B	108	0	0
		0700	A	467	9	1
		1100	B	< 1	0	0
		1500	A	167	6	6
		1900	B	11	46	38
		2300	A	54	0	0
7	5-11	0300	B	< 1	0	0
		0700	A			
		1100	B	599	2	0
		1500	A			
		1900	B	95	0	0
		2300	B			
8	5-12	0300	B	< 1	0	0
		0700	A			
		1100	B	389	8	3
		1500	A			
		1900	B	< 1	0	0
		2300	B			
9	5-13	0300	A	< 1	0	0
		0700	A			
		1100	B	< 1	0	0
		1500	A			

(continued)

TABLE 44 (concluded)

Test day	Date	Time	Sector code[a]	TOCl (ng/g)	Surrogate recovery d$_8$-Naphthalene (%)	Surrogate recovery d$_{12}$-Chrysene (%)
10	5-14	1500	B	< 1	0	50
		1900	A	2,700	5	10
	5-15	0300	A	22	68	68
		0700	A	8,070	30	32
		1100	B	< 1	0	0
		1500	B	< 1	0	0
		1900	A	< 1	0	0
		2300	B	< 1	4	5
11	5-16	0300	A	26	16	15
		0700	B	< 1	0	0
		1100	A	45	0	0
		1500	A	< 1	17	1
		1900	B	< 1	6	6
	5-17	0000	B	< 1	6	0

a The accessible portion of refuse was divided into two sectors which were sampled according to a randomized selection scheme.

TABLE 45. TOCl RESULTS AND SURROGATE RECOVERIES FOR CHICAGO NW TAP WATER SAMPLES

Test day	Date	TOCl (ng/ℓ)	Surrogate recovery d_8-Naphthalene (%)	Surrogate recovery d_{12}-Chrysene (%)
5	5-9	< 30	14	16
6	5-10	< 30	0	0
7	5-11	< 30	68	24
	5-14	< 30	12	10

TABLE 46. COMPOUNDS QUANTITATED IN SAMPLES FROM THE CHICAGO NW INCINERATOR, UNIT NO. 2

Compound	Composite day	Plant backbround air particulates concentration (ng/dscm)	Flue gas inlet concentration (ng/dscm)	Flue gas outlet concentration (ng/dscm)	Combined ash concentration (ng/g)	ESP Ash concentration (ng/g)
Target PAH Compounds						
Phenanthrene	1		120	200		
	2		32	110		
	3		28	340		
Fluoranthene	1	1.0	110	39	17	
	2		27	27		
	3	0.28	18	51	9.4	
Pyrene	1	0.82	300	92	12	
	2		140	91		
	3	0.18	57	77	7.8	
Additional Compounds Idendified						
1,3-Dichlorobenzene	1		130			
	2		130			
	3		18			
1,4-Dichlorobenzene	1		96			
	2		98			
	3		14			
1,2-Dichlorobenzene	1		140			
	2		120			
	3		20			
1,2,3-Trichlorobenzene	1		140	48		
	2		81	57		
	3		27	150		
1,2,4-Trichlorobenzene	1		550	200		
	2		380	220		
	3		160	560		
1,3,5-Trichlorobenzene	1		490	190		
	2		280	180		
	3		120	460		
Tetrachlorobenzene[a]	1		1,400	790		
	2		1,000	630		
	3		1,400			

(continued)

TABLE 46 (concluded)

Compound	Composite day	Plant backbround air particulates concentration (ng/dscm)	Flue gas inlet concentration (ng/dscm)	Flue gas outlet concentration (ng/dscm)	Combined ash concentration (ng/g)	ESP Ash concentration (ng/g)
Hexachlorobenzene	1		100	110		
	2		39	48		
	3		12	260		
Dichlorophenol[a]	1		560	240		
	2		240	280		
	3		190	630		
Trichlorophenol[a]	1		2,100	1,400		
	2		970	1,200		
	3		600	1,900		
Tetrachlorophenol[a]	1		2,200	1,500		
	2		1,100	1,100		
	3		600	1,700		
Pentachlorophenol	1		130	190		
	2			160		
	3		64	430		83
Dibenzofuran	1		86	100		
	2		28	67		
	3		23	140		
Dimethylphthalate	1					
	2				4.8	
	3				50	
Diethylphthalate	1					
	2					
	3					
Di-n-butylphthalate	1				15	
	2				6.1	
	3				32	
Butylbenzylphthalate	1					
	2					
	3					
Bis(2-ethylhexyl)phthalate	1				130	170
	2				47	230
	3				370	89

a Specific isomer not determined.

TABLE 47. COMPARISON OF TOCl RESULTS FROM DIRECT TOCl ASSAYS VERSUS CALCULATED TOCl FROM SPECIFIC COMPOUNDS IDENTIFIED IN COMPOSITE CHICAGO NW EXTRACTS

Sample type	Composite day	TOCl assay	Sum of compounds identified
Flue gas inlet	1	130 mg/hr	200 mg/hr
	2	88 mg/hr	110 mg/hr
	3	67 mg/hr	56 mg/hr
Flue gas outlet	1	97 mg/hr	120 mg/hr
	2	110 mg/hr	96 mg/hr
	3	86 mg/hr	190 mg/hr
ESP Ash	3	98 ng/g	93 ng/g

TABLE 48. CONCENTRATIONS OF POLYCHLORINATED BIPHENYL ISOMERS IN FLUE GAS OUTLET SAMPLES FROM THE CHICAGO NORTHWEST INCINERATOR UNIT NO. 2

Compound identified	Composite day (Concentration, ng/dscm) 1	2	3
Dichlorobiphenyl	5.8	6.0	40
Trichlorobiphenyl	7.6	4.3	36
Tetrachlorobiphenyl	4.2	1.5	13
Pentachlorobiphenyl	2.3	1.0	4.5
Total chlorobiphenyl	19.9	12.8	93.5

TABLE 49. CONCENTRATIONS OF POLYCHLORODIBENZO-P-DIOXINS AND FURANS IN FLUE GAS FROM THE CHICAGO NORTHWEST INCINERATOR

	Concentrations (ng/dscm)
Total trichlorodibenzo-p-dioxins	
Day 1	15
2	12
3	11
Mean	13
S.D.	2.1
Total trichlorodibenzofurans	
Day 1	350
2	280
3	270
Mean	300
S.D.	44
Total tetrachlorodibenzo-p-dioxins	
Day 1	7.2
2	5.4
3	6.2
Mean	6.3
S.D.	0.90
Total tetrachlorodibenzofurans	
Day 1	89
2	84
3	96
Mean	90
S.D.	6.0
Total hexachlorodibenzo-p-dioxins	
Day 1	14
2	21
3	14
Mean	16
S.D.	4.0

(continued)

TABLE 49 (concluded)

	Concentrations (ng/dscm)
Total hexachlorodibenzofurans	
Day 1	43
2	84
3	59
Mean	62
S.D.	21
Total heptachlorodibenzo-p-dioxins	
Day 1	7.2
2	7.8
3	7.7
Mean	7.6
S.D.	0.32
Total heptachlorodibenzofurans	
Day 1	7.2
2	7.2
3	8.0
Mean	7.5
S.D.	0.46
Octachlorodibenzo-p-dioxin	
Day 1	2.6
2	2.2
3	2.8
Mean	2.5
S.D.	0.39
Octachlorodibenzofuran	
Day 1	0.72
2	0.63
3	0.46
Mean	0.60
S.D.	0.13

TABLE 50. CONCENTRATIONS OF 2,3,7,8-TETRACHLORODIBENZO-P-DIOXIN IN FLUE GAS FROM THE CHICAGO NW INCINERATOR

	Concentration (ng/dscm)
Day 1	0.35
2	0.36
3	0.52
Mean	0.41
S.D.	0.10

Cadmium

The results for cadmium analysis of samples of fly ash, bottom ash, and refuse for test days 8 to 14 are presented in Tables 51 to 53. The fly ash samples contained the highest concentrations of cadmium, ranging from 86 to 560 µg/g. The concentration of cadmium in bottom ash was approximately one order of magnitude lower than that of the fly ash samples. The cadmium content of refuse samples ranged from less than 0.12 to 1.4 µg/g. Cadmium was not detected in the tap water from this plant. The concentrations of cadmium in the flue gas outlet samples are listed in Table 54. Also included in these tables are results for the recoveries of spiked samples, which was part of the QA program discussed in the analysis methods. The recovery of cadmium averaged 91% from both the combined ash and the refuse and 114% from the fly ash.

TABLE 51. CADMIUM CONCENTRATIONS IN FLY ASH FROM CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

Test day	Date	Time	Cadmium (μg/g)	Spike recovery (%)[a]
9	5/13	0000	283	139
		0400	201, 212 209, 217, 222	
		0800	376	
		1200	458	
		1600	391	
	5/14	1700	86.1, 82.3	
		2000	250	
10	5/15	0400	225	
		0800	209, 218	109
		1200	380, 392 419, 425, 440	124, 118, 114
		1600	361	
		200	560	
11	5/16	0000	306	135
		0400	325, 325	
		0800	237	
		1200	250	
		1600	216	
12	5/17	0100	230	94
		0500	279, 348	
		0900	289	
		1300	290	
		1700	313	100
		2100	328, 323	
13	5/18	0100	309	
		0500	326	
Spiked distilled water[b]				97 ± 9[c]

a Spiked with 10 μg total cadmium.

b Spiked with 10 μg total cadmium and analyzed with the sample digests.

c Mean and standard deviation for eight determinations.

TABLE 52. CADMIUM CONCENTRATIONS IN COMBINED BOTTOM ASH FROM CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

Test day	Date	Time	Cadmium (μg/g)	Spike recovery (%)[a]
9	5/13	0100	8.20	95
		0500	23.4	61
		0900	8.30, 7.34	
		1300	36.1, 31.2	
		1700	15.1	
	5/14	1700	5.40	88
		2100	30.8, 27.8	
10	5/15	0100	15.9, 9.20	81, 106
		0500	31.7	
		0900	48.8	
		1300	7.3	98
		1700	17.1	
		2100	18.5, 49.4 31.7, 60.5	67
11	5/16	0100	7.88, 28.7, 6.80	
		0500	27.8	120
		0900	13.3	105
		1300	10.7, 8.64	
		2000	12.1	
		2100	7.5	
12	5/17	0200	14.5	
		0600	10.4	
		1000	6.00	
		1400	14.3	
		1800	13.1, 14.8	
		2200	17.6	
13	5/18	0200	6.35	
		0600	8.00	
		1000	21.7	
		1400	4.60	
		1800	71	
		2200	3.60	
14	5/19	0200	13.1	
		0600	46.9	
		1000	7.85	
		1400	14.3	
Spiked distilled water[b]				93 ± 6[c]

a Spiked with 10 μg total cadmium.
b Spiked with 10 μg total cadmium and analyzed with the sample digests.
c Mean and standard deviation for six determinations.

TABLE 53. CADMIUM CONCENTRATIONS IN REFUSE FROM CHICAGO NORTHWEST INCINERATOR

Test day	Date	Time	Cadmium (μg/g)	Spike recovery (%)[a]
8	5/12	2300	1.45	
	5/13	0300	0.50, 1.25	
	5/13	0700	0.85	
	5/13	1100	0.28	91
	5/13	1500	0.45	
	5/14	1500	0.63	72
	5/14	1900	1.07	
	5/14	2300	0.95, 1.02	
10	5/15	0300	0.67	
	5/15	0700	0.14	95
	5/15	1100	0.85	106
	5/15	1500	< 0.12	
	5/15	1700	0.20	
	5/15	2300	1.10, 1.04	
11	5/16	0300	1.07	
	5/16	0700	0.83, 0.80	
	5/16	1100	< 0.12	
	5/16	1500	< 0.12, < 0.12	
	5/16	1900	0.63	
12	5/17	0000	1.10	
	5/17	0400	0.68	
	5/17	0800	< 0.12	
	5/17	1200	0.18	
	5/17	1600	0.16	105
	5/17	2000	0.60	
13	5/18	0000	0.57	
	5/18	1200	0.25	94
	5/18	1600	1.04, 0.94	
	5/18	2000	0.55	
14	5/19	0000	1.25	
	5/19	0400	9.85, 8.44	
	5/19	0800	0.79	
	5/19	1200	8.13	
Spiked distilled water[b]				78 ± 22[c]

a Spiked with 10 μg total cadmium.

b Spiked with 10 μg total cadmium and analyzed with the sample digests.

c Mean and standard deviation for seven determinations.

TABLE 54. CADMIUM CONCENTRATIONS IN THE FLUE GAS OUTLET PARTICULATES FROM CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

			Cadmium	
Test day	Date	Volume (dscm)	Mass (μg)	Concentration (μg/dscm)
12	5/17	6.20	520	84
13	5/18	6.20	1,490	240
14	5/19	6.81	1,850	272

SECTION 9

ANALYTICAL QUALITY ASSURANCE RESULTS

The principal quality assurance indicators used for this study were the recoveries for surrogate compounds spiked into all samples prior to extraction and the results of three interlaboratory comparison studies.

SURROGATE COMPOUND RECOVERIES

The surrogate recoveries determined for all samples from both plants are summarized in Table 55. As indicated in the previous section, the recoveries observed for naphthalene are generally lower than those for chrysene. Since the compounds of primary interest in this study are less volatile than naphthalene, the naphthalene recoveries likely indicate the maximum losses attributable to volatilization. The chrysene recoveries likely provide a more accurate indication of the recoveries of the principal analytes related to extraction efficiency and general extraction handling.

The apparent analytical accuracy and precision as indicated by the recoveries and standard deviations of surrogates observed for each media was likely influenced by the dilution of extracts prior to analysis. Many of the more complex extracts required dilution such that the concentrations of the surrogate compounds in the diluted extracts were near the analytical detection limits.

In general, the surrogate recoveries observed for the Ames samples were higher than those observed for the Chicago samples. This is likely attributable, at least in part, to the complexity of the Chicago samples.

INTERLABORATORY COMPARISON STUDIES

TOCl

Two interlaboratory comparison studies were conducted to check the comparability of TOCl assay as conducted by SwRI and GSRI. In the first study, selected extracts from the two plants were submitted for TOCl assay by the other laboratory. A second set of TOCl extracts was prepared at MRI by mixing several extracts of organic chemicals manufacturing wastewaters. The results of these two studies are shown in Table 56. Although some significant discrepancies are apparent, the data from the two laboratories are generally comparable.

TABLE 55. SUMMARY OF SURROGATE RECOVERY DATA

Plant	Sample type	Determinations	Surrogate recovery: d_8 Naphthalene (%)	Surrogate recovery: d_{12}-Chrysene (%)
Ames	Flue gas outlet	11	47 ± 12	86 ± 12
	Flue gas inlet	22	57 ± 24	73 ± 19
	Plant background air particulates	21	48 ± 23	98 ± 22
	ESP ash	51	44 ± 25	96 ± 22
	Bottom ash	51	55 ± 20	85 ± 31
	Coal	6	90 ± 16	90 ± 18
	RDF	36	65 ± 15	110 ± 28
	Bottom ash hopper quench water influent	6	69 ± 17	110 ± 18
	Bottom ash hopper quench water overflow	50	42 ± 32	88 ± 25
	Well water	3	44 ± 38	88 ± 17
Chicago	Flue gas outlet[a]	11 (resin) 11 (filter)	26 ± 23 29 ± 13	61 ± 37 62 ± 34
	Flue gas inlet[a]	11 (resin) 11 (filter)	41 ± 26 32 ± 17	93 ± 28 55 ± 22
	Plant background air particulates	12	31 ± 23	51 ± 45
	ESP ash	53	26 ± 18	35 ± 22
	Bottom ash	51	33 ± 18	21 ± 20
	Refuse	51	9 ± 13	10 ± 21
	Tap water	4	24 ± 30	13 ± 10

a The resin and filter catch portions of the Chicago flue gas samples were spiked, extracted, and analyzed separately for the surrogate compounds.

TABLE 56. RESULTS OF INTERLABORATORY TOCl ANALYSES

Sample	TOCl (ng/extract) GSRI results	SwRI results
Chicago flue gas outlet (5/15) resin[a]	44,500	23,000
Chicago flue gas inlet (5/7) particulate	26,700	19,200
Chicago flue gas outlet (5/12) resin	39,400	39,300
Chicago flue gas outlet (5/9) particulate	12,000	42,800
Chicago flue gas outlet (5/6) particulate	8,780	10,020
Chicago flue gas outlet (5/11) resin	47,900	31,400
Ames bottom ash (3/7, 0130 + 0530)[b]	227	1,020
Ames bottom ash (3/9, 2030)	91.8	124
Ames flue gas outlet (3/15)[c]	702	4,230
Ames flue gas outlet (3/18)[c]	443	18,100
Ames RDF (3/4, 0230)	78,800	109,000
Ames RDF (3/3, 1430)	181,000	215,000
Synthetic Extract I[d]	7,300	11,300
II	10,700	10,900
III	7,600	13,800
IV	10,400	12,400, 16,200

a Prepared by GSRI.

b Prepared by SwRI.

c Resin and particulate combined.

d Prepared by MRI.

Specific Compound Analysis

An interlaboratory study was also conducted using spiked fly ash aliquots spiked with specific compounds. Mixed fly ash from the Ames and Chicago plants was divided into 20-g aliquots. The aliquots were spiked by MRI with six chlorinated compounds and submitted to GSRI and SwRI for analysis by the same extraction, HRGC and scanning HRGC/MS procedures used for the plant samples. Four pairs of duplicate fly ash aliquots were submitted to each laboratory. The results of these analyses are shown in Table 57 along with the surrogate recoveries. Most compounds were identified in the spiked samples by both laboratories. Exceptions were pentachlorophenol in most samples and decachlorobiphenyl in one sample by SwRI.

TABLE 57. INTERLABORATORY COMPARISON OF ANALYTICAL RESULTS FOR THE EXTRACTION AND ANALYSIS OF SPECIFIC COMPOUNDS IN FOUR SETS OF QUALITY ASSURANCE SAMPLES

Compound	I			II			III			IV		
	Spike level (ng/g)	Concentration[a] (ng/g)		Spike level (ng/g)	Concentration[a] (ng/g)		Spike level (ng/g)	Concentration (ng/g)		Spike level (ng/g)	Concentration (ng/g)	
		GSRI	SwRI		GSRI	SwRI		GSRI	SwRI		GSRI	SwRI
1,2-Dichlorobenzene	0	ND[b]	ND	585	90, 125	952, 1,130	2,930	940, 430	7,420, 6,300	4,390	700, 1,010	20,200, 4,410
1,2,4-Trichlorobenzene	0	ND	ND	560	100, 170	1,170, 1,220	4,200	1,660, 865	11,700, 10,200	2,800	720, 855	7,660, 8,420
Hexachlorobenzene	0	ND	ND	550	45, 65	295, 150	2,750	790, 365	1,630, 1,680	275	85, 75	170, 103
2,4,6-Trichlorophenol	0	ND	ND	2,850	ND, 45	1,040, 748	570	75, ND	73, 112	4,280	355, 840	3,690, 2,040
Pentachlorophenol	0	ND	ND	2,680	ND, ND	tr,[c] tr	535	ND, ND	tr, tr	4,020	ND, ND	tr, tr
Decachlorobiphenyl	0	ND	ND	490	425, 970	tr, tr	1,230	6,050, 2,890	403, 566	2,450	8,650, 6,800	2,460, 1,280
Surrogate Compound Recovery (%)												
Naphthalene-d_8		38, 2	88, 88		25, 40	89, 88		59,30	98, 84		34, 42	101, 89
Chrysene-d_{12}		49, 23	73, 84		41, 40	88, 76		50, 38	75, 71		45, 45	111, 103

a Concentration values reported for two identical samples prepared by MRI.

b ND = not detected.

c tr = trace.

PCDD and PCDF Analysis

The results of the interlaboratory comparison of PCDD and PCDF analyses conducted on Chicago flue gas outlet extracts by MRI and R. Harless at EPA's Research Triangle Park laboratory are shown in Table 58. Both the qualitative and quantitative results from the two laboratories were quite comparable. There were no qualitative discrepancies. The agreement in quantitation is reasonable, particularily in view of the facts that: (1) the two laboratories utilized different gas chromatographic systems and different selected ion monitoring procedures (computer controlled ion selection by MRI and hardware controlled ion selection by EPA) and (2) that the levels were near the limits of detection.

TABLE 58. INTERLABORATORY COMPARISON OF THE LEVELS OF PCDDs AND PCDFs IN COMPOSITE EXTRACTS FROM THE CHICAGO NW INCINERATOR

Composite	Parameter	Total mass in sample (ng) MRI results	EPA[a] results
1	2,3,7,8-Tetrachlorodibenzo-p-dioxin	24	14
2	2,3,7,8-Tetrachlorodibenzo-p-dioxin	24	7.0
3	2,3,7,8-Tetrachlorodibenzo-p-dioxin	34	9.4
4	Total tetrachlorodibenzo-p-dioxin	500	1,200
5	Total tetrachlorodibenzo-p-dioxin	360	740
6	Total tetrachlorodibenzo-p-dioxin	400	660
7	Total tetrachlorodibenzofuran	5,600	1,640
8	Total hexachlorodibenzo-p-dioxin	1,400	280

a Calculated from data in Reference 8.

SECTION 10

EMISSIONS RESULTS

AMES MUNICIPAL POWER PLANT, UNIT NO. 7

The TOCl input and emission rates determined for the Ames plant during the test period are shown in Table 59. These results were calculated from the daily mean levels of TOCl in coal, RDF, and ash from Section 8 and the mass and volume flow rates from the engineering and process data in Section 7.

Since TOCl is not a conservative parameter, it is not surprising that the mean TOCl destruction rate is greater than 99%. Interestingly, these data indicate that flue gas was responsible for the largest fraction of TOCl emissions, 83%. Bottom ash and fly ash contributed only 11 and 5%, respectively, of the total emissions.

Table 60 shows the input and emission rates for the target PAHs and other compounds identified in the composited Ames extracts. The mass and volume flow data used for the input and emission calculations are averages for the sampling days comprising the composite days.

The emission rates for PCBs in the Ames flue gas samples are shown in Table 61. Only the composited flue gas outlet extracts were analyzed for PCBs by HRGC/MS-SIM. PCBs may have been present in other inputs and emissions media at concentrations below the limit of detection of scanning HRGC/MS.

A summary of the cadmium inputs and emissions for the test days investigated at the Ames Municipal Power Plant is presented in Table 62. The total inputs and emissions represent a good mass balance.

CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

The calculated TOCl inputs and emissions are shown in Table 63. The apparent mean TOCl destruction rate (97%) is slightly lower than was observed for the Ames plant. However, the difficulty experienced in taking representative samples of raw refuse hinders accurate destruction efficiency determinations. The contribution of flue gases to total TOCl emissions is remarkably similar, 87% for the Chicago incinerator relative to 83% for Ames power plant.

TABLE 59. TOTAL ORGANIC CHLORINE INPUTS AND EMISSIONS - AMES MUNICIPAL POWER PLANT, UNIT NO. 7

			Inputs							Emissions												
			Coal			Refuse-derived fuel			Total	Bottom ash			ESP ash			Flue gas[b]			Total	Percent of TOCl emissions		
Date	Load (%)	RDF feed (%)	Feed (kg/hr)	TOCl conc. (ng/g)	TOCl input (mg/hr)	Feed (kg/hr)	TOCl conc. (ng/g)	TOCl input (mg/hr)	TOCl input (mg/hr)	Mass flow (kg/hr)[a]	TOCl conc. (ng/g)	TOCl emissions (mg/hr)	Mass flow (kg/hr)	TOCl conc. (ng/g)	TOCl emissions (mg/hr)	Mass emissions (dscm/hr)	TOCl conc. (ng/dscm)	TOCl emissions (mg/hr)	TOCl emissions (mg/hr)	BA	FA	Flue gas
3/2	86	0	14,600	5	73	0				100	5.5	0.55	1,200	4.7	5.6	309,200	156	48.2	54.6	1	10	89
3/3	86	13	14,400	5	72	2,130	20,100	42,900	43,000	350	124	43	1,200	2.5	3.0	323,800[c]	1,210	392	438	10	1	89
3/4	90	23	14,400	5	72	4,290	9,300	39,900	40,000	550	97	53	1,200	6.5	7.8	328,000[c]	766	251	312	17	3	80
3/5	91	19	15,200	5	76	3,640	3,500	12,700	12,800	450	36	16	1,200	5.2	6.2	322,500[c]	454	146	168	10	3	87
3/6	89	22	14,600	5	73	4,030	8,200	33,050	33,100	550	44	26	1,200	2.7	3.2	340,300[c]	951	324	351	7	1	92
3/7	87	14	15,200	5	76	2,470	9,900	24,500	24,600	400	55	22	1,200	3.1	3.7	318,400[c]	412	131	156	14	2	84
3/8	80	20	12,800	5	64	3,180	12,100	38,500	38,600	500	33	17	1,200	56	67	291,300[c]	367	107	191	9	35	56
3/9	60	4	10,800	5	54	491	5,000	2,500	2,600	200	4.4	0.88	1,200	3.5	4.2	242,900[c]	411	100	105	1	4	95
3/10	83	10	14,200	5	71	1,530	5,300	8,100	8,200	300	38	11.4	1,200	5.2	6.2	333,300[c]	833	278	296	4	2	94
3/11	88	24	13,700	5	68.5	4,340	13,000	56,400	56,500	558	113	67	1,200	2.6	3.1	341,500[c]	562	192	257	24	1	75
3/12	89	21	16,000	5	80.0	4,320	19,900	86,000	86,100	500	57	29	1,200	3.2	3.8							
3/13	89	16	14,100	5	70.5	2,720	9,600	26,100	26,200	400	156	62	1,200	2.3	3.8	328,900	332	109	174	36	2	62
3/14	87	24	13,900	5	69.5	4,350	22,000	95,700	95,800	550	38	21	1,200	3.0	3.6	289,300	1,680	486	511	4	1	95
3/15	62	4	10,900	5	54.5	417				200			1,200			258,400	238	61.5				
3/17	84	12	14,200	5	71	1,850				350			1,200			325,400	950	309				
3/18	91	17	14,300	5	71.5	2,930				500			1,200			319,100	855	273				
3/19	89	15	14,200	5	71	2,550				400			1,200			314,800	1,050	331				
3/20	87	7	15,600	5	78	1,200				250			1,200			320,000	205	65.6				
3/22	84	11	14,100	5	70.5	1,740				350			1,200			332,200	124	41.2				
3/23	52	0	9,250	5	46.3	0				100			1,200			225,700	157	35.4				
Determinations	20	20	20	20	20	20	12	12	12	20	13	13	20	13	13	19	19	19	12	12	12	12
Mean	83	14	13,800	5	69	2,312	11,500	38,900	39,000	380	62	28	1,200	7.7	9.2	308,700	616	194	246	11	5	83
Standard deviation	11	7.7	1,700	ND	8.4	1,570	6,200	28,800	28,800	150	47	21	ND	14.6	17.4	32,900	425	134	138	10	10	13

a Estimated from mass emissions data collected during 1978. Douglas Fiscus, Midwest Research Institute, personal communication.

b Flue gas sampled at the outlet of the ESP except where indicated.

c Flue gas outlet samples were not collected on this day. The mass emissions and TOCl concentration data are for flue gas inlet samples collected on this day. Flue gas TOCl emissions are corrected for the TOCl in the ESP ash.

TABLE 60. COMPOUNDS QUANTITATED IN THE PRIMARY INPUT AND EMISSION MEDIA FOR THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

		Inputs						Emissions							
		Coal		Refuse-derived fuel		Plant background air		Flue gas inlet		Flue gas outlet		ESP ash		Bottom ash	
Compound	Composite day	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/dscm)	Input rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)
Target PAH compounds															
Phenanthrene	1	7,550	110,000			0.29	0.04	270	76	390	110	0.3	0.4	32	3.2
	2	9,090	130,000	1,400	3,100	0.6	0.09	420	140	320	100			250	99
	3	15,400	210,000	940	4,100	0.8	0.11	660	200	320	96	0.2	0.2	140	78
	4	8,500	110,000	948	1,800	0.8	0.13	640	200	37	12	0.2	0.2	43	14
	5	18,600	270,000	828	1,800	0.32	0.044	200	54	480	13	0.2	0.2	500	180
Anthracene	1	1,570	23,000					59	16	49	14				
	2	1,840	26,000	296	810	0.17	0.028	57	18	77	26				
	3	1,260	18,000			0.16	0.024	77	22	78	24			24	13
	4	2,120	28,000			0.19	0.030	89	28	46	14				
	5	4,110	59,000					100	28	77	22			130	46
Fluoranthene	1	1,190	17,000			0.36	0.05	70	20	46	13			10	1.0
	2	1,640	23,000	984	1,300	0.7	0.11	240	78	40	13			52	21
	3	3,320	46,000	271	1,200	0.7	0.11	140	42	97	30			30	17
	4	900	12,000	306	580	1.0	0.16	87	28	28	8.8				
	5	3,210	46,000	198	420	0.5	0.07	94	26	130	36			450	160
Pyrene	1	1,340	20,000			0.36	0.05	220	64	110	32			9.0	0.90
	2	1,960	28,000	552	1,500	0.7	0.12	850	280	96	32			64	26
	3	3,810	53,000	436	1,900	0.7	0.11	480	140	250	74			29	16
	4	1,070	14,000	282	530	1.1	0.17	230	74	66	22			6.0	1.9
	5	4,040	58,000	372	790	0.5	0.07	330	90	330	90			420	150
Chrysene	1	370	5,400			0.29	0.04	3.5	1.0			0.3	0.4		
	2	425	6,000	434	1,200	0.40	0.07	28	8.0						
	3	1,060	15,000			0.37	0.06								
	4	238	3,200			0.60	0.09	9.6	3.2						
	5	1,300	19,000			0.38	0.05	2.8	0.76	2.7	0.76			170	58
Benzo[a]pyrene	1					0.07	0.01	21	6.0	13	3.8				
	2					0.17	0.28	64	22						
	3					0.11	0.016	120	38						
	4					0.09	0.015	19	6.2	28	6.0				
	5					0.07	0.008	63	17						
Indeno[1,2,3-c,d]pyrene	1														
	2														
	3														
	4					0.02	0.003								
	5														
Benzo[g,h,i]perylene	1									3.3	0.96				
	2														
	3									22	6.6				
	4					0.09	0.015			4.6	1.5				
	5														

(continued)

TABLE 60 (Continued)

Compound	Composite day	Inputs: Coal Conc. (ng/g)	Inputs: Coal Input rate (mg/hr)	Inputs: Refuse-derived fuel Conc. (ng/g)	Inputs: Refuse-derived fuel Input rate (mg/hr)	Inputs: Plant background air Conc. (ng/dscm)	Inputs: Plant background air Input rate (mg/hr)	Emissions: Flue gas inlet Conc. (ng/dscm)	Emissions: Flue gas inlet Emission rate (mg/hr)	Emissions: Flue gas outlet Conc. (ng/dscm)	Emissions: Flue gas outlet Emission rate (mg/hr)	Emissions: ESP ash Conc. (ng/g)	Emissions: ESP ash Emission rate (mg/hr)	Emissions: Bottom ash Conc. (ng/g)	Emissions: Bottom ash Emission rate (mg/hr)
Additional compounds identified															
Dichlorobenzene	1									3.3	1.0				
	2			1,300	3,500			25	8.2					24	9.6
	3			1,200	5,200			79	24			0.07	0.08		
	4			520	980					5	1.5				
	5			430	920			25	6.8						
1,2,4-Trichlorobenzene	1														
	2					0.02	0.0028	99	32						
	3					0.01	0.0016	180	52	110	34				
	4														
	5							69	19	85	24				
Hexachlorobutadiene	1														
	2														
	3					0.02	0.0024	103	30						
	4														
	5														
Tetrachlorobenzene[a]	1														
	2														
	3														
	4														
	5														
Pentachlorophenol	1					0.07	0.010								
	2			1,300	3,500										
	3							24	7.2						
	4														
	5			690	1,500										
Phenol	1	10,000	150,000			3.3	0.46	4,700	1,300	6,400	1,800	220	260	980	98
	2	12,000	170,000			1.3	0.21	4,000	1,300	7,700	2,600			1,600	640
	3	2,800	39,000			0.8	0.11	13,000	4,000	3,000	920			1,800	990
	4	23,000	310,000			1.5	0.23	5,100	1,600	6,000	1,900	190	230	360	110
	5	29,000	420,000			1.8	0.25	9,500	2,600	6,200	1,700	380	460	730	260
2,4-Dimethylphenol	1									1,000	300				
	2									1,200	400			27	11
	3									1,300	400				
	4													8	2.5
	5									2,100	580				

(continued)

TABLE 60 (Continued)

		Inputs						Emissions							
		Coal		Refuse-derived fuel		Plant background air		Flue gas inlet		Flue gas outlet		ESP ash		Bottom ash	
Compound	Composite day	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/dscm)	Input rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)
Naphthalene	1	1,400	20,000			0.28	0.040	710	200	650	190	0.17	0.2	15	1.5
	2	1,100	16,000	36,000	98,000	0.22	0.037	1,000	340	550	180			360	140
	3	1,800	25,000	2,200	9,600	0.32	0.048	620	190	81	24			110	61
	4	1,800	24,000	1,500	2,800	0.28	0.045	1,800	560	300	98			29	9.2
	5	2,700	39,000	1,500	3,200	0.13	0.017	740	200	850	240	0.18	0.22		
Fluorene	1	3,500	50,000												
	2	3,100	43,000	600	1,600	0.22	0.037								
	3	5,600	78,000	450	1,900	0.32	0.048	120	34					14	7.7
	4	3,300	45,000	380	712	0.28	0.045								
	5	7,000	100,000	320	677	0.13	0.017								
Benz[a]anthracene	1					0.14	0.020								
	2					0.44	0.073								
	3					0.53	0.079	7.2	2.2						
	4					0.55	0.089								
	5					0.38	0.052								
Benzofluoranthrene	1	261	3,800			0.42	0.060			6.5	1.9				
	2	470	6,600			0.67	0.11	9.9	3.2	2.7	0.88				
	3	960	13,000			0.63	0.095			12	3.6				
	4	260	3,400			0.65	0.1			6.9	2.2				
	5	1,200	18,000			0.51	0.070	17	2.3						
Benzo[e]pyrene	1														
	2														
	3									29	8.8				
	4														
	5														
Acenaphthene	1	650	9,500												
	2	970	14,000	1,200	3,200										
	3	1,600	22,000											1.0	0.55
	4	1,400	18,000												
	5	1,500	22,000												
Acenaphthylene	1	220	3,200											120	12
	2	240	3,400					20	6.6					75	30
	3	560	7,700					24	7.2					10	5.5
	4	400	5,300											100	32
	5	450	6,500											130	47
Trichlorobenzene[a]	1									36	10.2				
	2									77	26				
	3									24	7.2				
	4														
	5														

(continued)

TABLE 60 (concluded)

		Inputs						Emissions							
		Coal		Refuse-derived fuel		Plant background air		Flue gas inlet		Flue gas outlet		ESP ash		Bottom ash	
Compound	Composite day	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/g)	Input rate (mg/hr)	Conc. (ng/dscm)	Input rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)
Dimethylphthalate	1													3.0	0.30
	2														
	3														
	4											0.20	0.48		
	5			730	1,600										
Diethylphthalate	1											11	26		
	2			9,100	25,000							0.5	1.20	37	15
	3			290	1,300										
	4			1,400	2,700							2.0	48	16	5.1
	5			11,000	23,000										
Di-n-butylphthalate	1											15	36	4.0	0.40
	2			18,000	49,000							3.0	7.2	42	16.8
	3			14,000	61,000									12	6.6
	4			6,400	12,000							4.0	9.6	35	11
	5			14,000	28,000									170	58
Butylbenzylphthaalte	1											6.0	14	32	3.2
	2														
	3													51	28
	4			59,000	110,000					6.0	14				
	5			22,000	46,000										
Bis(2-ethylhexyl)-phthalate	1											3.0	7.2	980	9.8
	2			350,000	970,000							2.0	4.8	1,200	470
	3			44,000	190,000									480	260
	4			35,000	66,000							8.0	19	810	260
	5			22,000	46,000										

a Specific isomer not determined.

TABLE 61. FLUE GAS CONCENTRATIONS OF PCBs AND EMISSION RATES FOR THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

	Total PCBs	
	Concentrations (ng/dscm)	Emission rate (mg/hr)
Ames composite day 1	5.2	1.4
2	27	9.0
3	23	6.8
4	25	8.2
5	17	4.8
Mean	19	6.0
S.D.	8.8	3.0

TABLE 62. CADMIUM INPUTS AND EMISSIONS - AMES MUNICIPAL POWER PLANT, UNIT NO. 7

				Input							Emissions												
				Coal			RDF			Total	Bottom ash (BA)			ESP ash (FA)			Flue gas				Percent of total emissions		
Test day	Date	Load (%)	RDF (%)	Mass flow (kg/hr)	Cd conc. (µg/g)	Cd input (mg/hr)	Mass flow (kg/hr)	Cd conc. (µg/g)	Cd input (mg/hr)	Cd input (mg/hr)	Mass flow (kg/hr)	Cd conc. (µg/g)	Cd emissions (mg/hr)	Mass flow (kg/hr)	Cd conc. (µg/g)	Cd emissions (mg/hr)	Volume flow (dscm/hr)	Cd conc. (µg/dscm)	Cd emissions (mg/hr)	Total emissions (mg/hr)	BA	FA	Flue gas
11	3/12	89	23.5	13,900			4,300				550			1,200	9.01	10,800							
12	3/13	89	15.3	15,010	0.736	11,050	2,700	2.10	5,670	16,700	400	1.91	760	1,200	8.36	10,030	164,000						
13	3/14	87	23.8	13,800	0.135	1,860	4,300	3.16	13,600	15,500	550	2.19	1,200	1,200	8.21	9,850	145,000						
14	3/15	62	3.69	10,800	0.138	1,490	410	5.30	2,170	3,660	150	2.41	360	1,200	5.43	6,520	129,000						
	3/16				0.144							0.876		1,200	2.90	3,480							
21	3/24	85	6.15	14,800	0.149	2,200	970	2.63	2,550	4,750	200	1.36	270	1,200	4.12	4,940	153,000	22.55	3,450	8,660	3	57	40
22	3/25	84	10.9	14,300	0.112	1,600	1,740	2.88	5,010	6,610	300	2.70	810	1,200	6.34	7,600	148,000	27.95	4,140	12,600	6.5	60.5	33
23	3/26	87	15.0	14,400	0.231	3,320	2,530	2.82	7,130	10,500	400	2.30	920	1,200	7.54	9,050	148,000	25.46	3,770	13,700	7	66	27
Determinations		7	7	7	7	6	7	6	6	6	7	7	6	8	8	8	6	3	3	3	3	3	3
Mean		83	16	13,900	0.235	3,590	2,420	3.15	6,020	9,620	360	1.96	720	1,200	6.48	7,780	148,000	25.3	3,790	11,600	5.5	61	33
Standard deviation		9.5	7.8	1,420	0.224	3,720	1,510	1.11	4,160	5,540	160	0.64	350		2.2	2,630	11,400	2.70	350	2,650	2.2	4.5	6.5

TABLE 63. TOTAL ORGANIC CHLORINE INPUTS AND EMISSIONS - CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

	Refuse input			Emissions									
				Combined ash			Flue gas[a]			Total			
Date	Feed rate (kg/hr)	TOCl conc. (ng/g)	TOCl input (mg/hr)	Mass flow (kg/hr)	TOCl conc. (ng/g)	TOCl emissions (mg/hr)	Mass emissions (dscm/hr)	TOCl conc. (ng/dscm)	TOCl emissions (mg/hr)	TOCl emissions (mg/hr)	Percent of TOCl emissions: Combined ash (%)	Percent of TOCl emissions: Flue gas (%)
5/3	15,800	4,300	67,900	5,500	< 1	< 5.5	-	-	-	-	-	-
5/4	15,200	110	1,670	5,290	< 1	< 5.3	88,080	1,100	97	102	5	95
5/6	20,300	0	0	5,490	3	16	93,960	3,140	295	311	5	95
5/7	17,300	470	8,100	4,680	2.9	14	84,600	1,760	149	163	9	91
5/8	17,300	260	4,500	4,680	21	87	92,460	13,500	1,250	1,337	6	94
5/9	18,200	730	13,300	4,920	21	103	72,600	2,070	150	253	41	59
5/10	18,400	130	2,390	4,970	12	60	83,820	3,310	277	337	18	82
5/11	18,900	230	4,350	5,110	2.2	11	85,740	2,540	218	229	5	95
5/12	16,000	130	2,100	3,470	15	53	86,280	2,920	252	305	17	83
5/13	15,800	< 1	< 16	3,430	10	34	83,340	1,230	103	137	25	75
5/15	16,900	1,350	22,800	3,670	6.6	24	84,600	2,300	195	219	1.1	89
5/16	16,600	12	200	3,600	< 1	< 3.6	99,060	1,490	148	152	3	97
5/17	17,200	< 1	< 17	3,730	-	-	-	-	-	-	-	-
Determinations	13	13	12	13	12	12	11	11	11	11	11	11
Mean	17,200	590	9,800	4,500	8.1	35	86,780	3,200	285	327	13	87
Standard deviation	1,440	1,180	18,700	800	7.6	34	6,830	3,500	327	345	12	12

a Flue gas collected at the outlet of the ESP.

The input and emission rates for target PAHs and other compounds identified in the composited Chicago extracts are shown in Table 64. Since the refuse extracts contained very high levels of extracted organics and were very difficult to analyze, composite refuse extracts were not prepared. Hence, the data were not available for the target PAHs and other compounds in the primary input medium for these composite days.

The emission rates for PCBs in the Chicago flue gas samples are shown in Table 65. As in the case of the Ames data, only flue gas data was available although PCBs may have been present in other media at low concentrations.

The emission rates for PCDDs and PCDFs in the Chicago flue gas samples are shown in Table 66. The mean emission rates for total PCDDs and PCDFs are 3,900 and 38,600 μg/hr, respectively. Table 67 shows the flue gas emission rates for 2,3,7,8-tetrachlorodibenzo-p-dioxin. The mean emission rate is 34 μg/hr.

A summary of the cadmium inputs and emissions for the test days investigated is presented in Table 68. The agreement between the total cadmium inputs and emissions is poor and reflects the problems encountered in obtaining representative samples of the refuse materials and resulting ashes.

TABLE 64. COMPOUNDS QUANTITATED IN INPUT AND EMISSION MEDIA CHICAGO NW INCINERATOR, UNIT NO. 2

Compound	Composite day	Plant background air Conc. (ng/dscm)	Plant background air Input rate (mg/hr)	Flue gas inlet Conc. (ng/dscm)	Flue gas inlet Emission rate (mg/hr)	Flue gas outlet Conc. (ng/dscm)	Flue gas outlet Emission rate (mg/hr)	Combined ash Conc. (ng/g)	Combined ash Emission rate (mg/hr)
Target PAH compounds									
Phenanthrene	1			120	11	200	17		
	2			32	2.8	110	9.2		
	3			28	2.4	340	28		
Fluoranthene	1	1.0	0.044	110	9.8	39	3.4	17	78
	2			27	2.4	27	2.2		
	3	0.28	0.012	18	1.6	51	4.4	9.4	38
Pyrene	1	0.82	0.035	300	26	92	8.0	12	56
	2			140	12	91	7.8		
	3	0.18	0.008	57	4.8	77	6.6	7.8	32
Additional compounds identified									
1,3-Dichlorobenzene	1			130	12				
	2			130	11				
	3			18	1.6				
1,4-Dichlorobenzene	1			96	8.2				
	2			98	8.2				
	3			14	1.2				
1,2-Dichlorobenzene	1			140	12				
	2			120	10				
	3			20	17				
1,2,3-Trichlorobenzene	1			140	12	48	4.0		
	2			81	7.0	57	4.8		
	3			27	2.2	150	12		
1,2,4-Trichlorobenzene	1			550	46	200	17		
	2			380	32	220	19		
	3			160	13	560	48		
1,3,5-Trichlorobenzene	1			490	44	190	16		
	2			280	24	180	15		
	3			120	10	460	40		
Tetrachlorobenzene[a]	1			1,400	120	790	68		
	2			1,000	86	630	54		
	3			470	40	1,400	120		
Hexachlorobenzene	1			100	9.0	110	9.0		
	2			39	3.4	48	4.0		
	3			12	1.0	260	22		

(continued)

TABLE 64 (Concluded)

Compound	Composite day	Plant background air		Flue gas inlet		Flue gas outlet		Combined ash		
		Conc. (ng/dscm)	Input rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/dscm)	Emission rate (mg/hr)	Conc. (ng/g)	Emission rate (mg/hr)	
Dichlorophenol[a]	1			560	40	240	22			
	2			240	20	280	24			
	3			190	16	630	54			86
Trichlorophenol[a]	1			2,100	180	1,400	120			
	2			970	82	1,200	98			
	3			600	52	1,900	160			
Tetrachlorophenol[a]	1			2,200	190	1,500	130			
	2			1,100	90	1,100	96			
	3			600	52	1,700	140			
Pentachlorophenol	1			130	11	190	16			
	2					160	14			83
	3			64	5.4	430	36			
Dibenzofuran	1			86	7.4	100	8.8			
	2			28	2.4	67	5.8			
	3			23	2.0	140	11			
Dimethylphthalate	1									
	2					4.8	42			
	3					50	400			
Diethylphthalate	1									
	2									
	3									
Di-n-butylphthalate	1					15	144			
	2					6.1	54			
	3					32	260			
Butylbenzylphthalate	1									
	2									
	3									
Bis(2-ethylhexyl)-	1					130	1,200			
	2					47	420			
	3					370	3,000			

a Specific isomer not determined.

TABLE 65. FLUE GAS CONCENTRATIONS OF PCBs AND EMISSION RATES FOR THE CHICAGO NORTHWEST INCINERATOR UNIT NO. 1

	Concentrations (ng/dscm)	Emission rate (mg/hr)
Composite day 1	20	1.7
2	13	1.1
3	93	7.8
Mean	42	3.5
S.D.	45	3.7

TABLE 66. CONCENTRATIONS OF POLYCHLORODIBENZO-P-DIOXINS AND FURANS IN FLUE GAS FROM THE CHICAGO NORTHWEST INCINERATOR AND CORRESPONDING EMISSION RATES

	Concentrations (ng/dscm)	Emission rate (μg/hr)
Total trichlorodibenzo-p-dioxins		
Day 1	15	1,300
2	12	1,000
3	11	920
Mean	13	1,100
S.D.	2.1	200
Total trichlorodibenzofurans		
Day 1	350	30,000
2	280	24,000
3	270	22,000
Mean	300	25,000
S.D.	44	4,000
Total tetrachlorodibenzo-p-dioxins		
Day 1	7.2	620
2	5.4	460
3	6.2	520
Mean	6.3	530
S.D.	0.90	81
Total tetrachlorodibenzofurans		
Day 1	89	7,600
2	84	7,200
3	96	8,000
Mean	90	7,600
S.D.	6.0	400
Total hexachlorodibenzo-p-dioxins		
Day 1	14	1,200
2	21	1,800
3	14	1,200
Mean	16	1,400
S.D.	4.0	350

(continued)

TABLE 66 (concluded)

	Concentrations (ng/dscm)	Emission rate (µg/hr)
Total hexachlorodibenzofurans		
Day 1	43	3,800
2	84	7,200
3	59	5,000
Mean	62	5,300
S.D.	21	1,700
Total heptachlorodibenzo-p-dioxins		
Day 1	7.2	620
2	7.8	660
3	7.7	660
Mean	7.6	650
S.D.	0.32	23
Total heptachlorodibenzofurans		
Day 1	7.2	620
2	7.2	620
3	8.0	680
Mean	7.5	640
S.D.	0.46	34
Octachlorodibenzo-p-dioxin		
Day 1	2.6	220
2	2.2	190
3	2.8	240
Mean	2.5	220
S.D.	0.39	25
Octachlorodibenzofuran		
Day 1	0.72	62
2	0.63	54
3	0.46	40
Mean	0.60	52
S.D.	0.13	11

TABLE 67. CONCENTRATIONS OF 2,3,7,8-TETRACHLORODIBENZO-P-DIOXIN IN FLUE GAS FROM THE CHICAGO NW INCINERATOR AND CORRESPONDING EMISSION RATES

	Concentration (ng/dscm)	Emission rate (μg/hr)
Day 1	0.35	30
2	0.36	30
3	0.52	44
Mean	0.41	34
S.D.	0.10	8.0

TABLE 68. CADMIUM INPUT AND EMISSIONS FROM CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

					Emissions								
		Refuse input			Combined ash			Flue gas[a]			Total	Percent of total emissions	
Test day	Date	Mass feed (kg/hr)	Cd conc. (μg/g)	Cd input (mg/hr)	Mass emissions (kg/hr)	Cd conc. (μg/g)	Cd emissions (mg/hr)	Volume emissions (dscm/hr)	Cd conc. (μg/dscm)	Cd emissions (mg/hr)	Cd emissions (mg/hr)	Combined ash (%)	Flue gas (%)
8	5/12	16,000	1.45[b]	23,200[b]	3,470								
9	5/13	17,500	0.54	9,450	3,800	17.6	66,900						
10	5/15	16,900	0.47	7,940	3,670	26.6	97,600						
11	5/16	16,600	0.52	8,630	3,600	14.5	52,200						
12	5/17	17,200	0.48	8,260	3,730	12.8	47,700	87,200	285	24,900	72,600	66	34
13	5/18	17,500	0.59	10,300	3,800	8.55	32,500	97,500	240	23,400	55,900	58	42
14	5/19	22,400	6.02[b]	135,000[b]	7,460	20.5	153,000	100,500	273	27,400	180,400	85	15
Determinations		7	5	5	7	6	6	3	3	3	3	3	3
Mean		17,700	0.52	8,920	4,220	16.8	75,000	95,100	266	25,200	103,000	70	30
Standard deviation		2,100	0.05	960	1,430	6.3	44,100	7,000	23	2,020	67,600	14	14

a Flue gas collected at the outlet of the ESP.

b Not included in determinations of mean and standard deviation.

SECTION 11

STATISTICAL SUMMARY OF PILOT STUDY DATA

OVERVIEW

This section summarizes the data obtained from the chemical analysis of specimens collected in the pilot study. The chemical analysis was performed in two phases or tiers. In the first tier, the total organic chlorine (TOCl) concentration was measured in nearly all of the specimens collected. Some compositing of specimens was performed before chemical analysis to reduce cost. In the second tier, many more specimens were composited because of the greater expense at this level of analysis. Also, only specimens from selected media were analyzed.

For the first tier chemical analysis data, the mean, coefficient of variation (CV) and nominal 95% confidence intervals for the TOCl concentration are calculated for each sampling location at both combustion sites. The mean and CV are calculated for the concentrations of compounds quantified in the second tier analysis. In addition, the total mass flow rate and its CV are calculated. The mass flow rate is calculated by weighting the measured concentration of the compounds by the total mass flow rate associated with each measurement.

The summary statistics are presented below with brief descriptions of the calculation methods.

FIRST TIER SUMMARY

Total Organic Chlorine

For the sampling locations where each specimen was chemically analyzed independently (no compositing) the arithmetic mean ($\bar{X}$) was calculated using the equation

$$\bar{X} = \sum_{i=1}^{n} X_i/n \quad ,$$

where X_i is the TOCl concentration of the i^{th} specimen and n is the number of specimens. The CV is calculated by first calculating the sample variance (S^2)

$$S^2 = \sum_{i=1}^{n} (X_i - \bar{X})^2/(n - 1) \; .$$

The CV = $S/\bar{X}$. The nominal 95% confidence intervals are calculated by

$$(\bar{X} - t_{.05}(df)\; S/\sqrt{n} \; , \; \bar{X} + t_{.05}(df)\; S/\sqrt{n}) \; .$$

where $t_{.05}(df)$ is obtained from tables of Student's t distribution[9] and df denotes the appropriate number of degrees of freedom, which is equal to the number of independent chemical analyses minus one.

For several media many specimens were collected. To minimize the cost of chemical analysis for these media while retaining sufficient statistical information, a complex compositing protocol was developed for the sample locations where more than one specimen per day was collected. The compositing varied for the samples collected each day. On some days all were composited, on others the two within a shift were composited, and on others none were composited. These locations were fly ash, bottom ash, coal, RDF and OW at Ames and fly ash, combined ash and refuse at Chicago, NW. No compositing was done for the specimens collected at the other sample locations.

To modify the calculations for $\bar{X}$ and S^2 to compensate for the compositing, each chemical determination was assigned a weight equal to the number of specimens composited. Then the weighted mean $\bar{Y}_w$ was calculated by

$$\bar{Y}_w = \sum_{i=1}^{m} W_i \, Y_i \; / \sum_{i=1}^{m} W_i \; ,$$

where Y_i is the i^{th} chemical determination, W_i is the number of specimens composited for the i^{th} chemical determination and m is the number of chemical determinations. Because $\sum_{i=1}^{m} W_i = n$ and, on average,

$$\sum_{i=1}^{m} W_i \, Y_i = \sum_{i=1}^{n} X_i, \text{ then } \bar{Y}_w \text{ equals } \bar{X}, \text{ on average.}$$

To estimate S^2 from the composited data, calculate

$$S_w^2 = \sum_{i=1}^{m} W_i^2 \, (Y_i - \bar{Y}_w)^2 \Big/ \sum_{i=1}^{m} W_i$$

where W_i, Y_i, $\bar{Y}_w$, and m are the same as above. Because $\sum_{i=1}^{m} W_i^2 \, (Y_i - \bar{Y}_w)^2$ approximately equals $\sum_{i=1}^{n} (X_i - \bar{X})^2$ on average, S_w^2 approximately equals S^2 on average. Hence the CV ($S/\bar{X}$) is estimated by $S_w/\bar{Y}_w$.

The technique above gives a method to estimate $\bar{X}$ and S^2 as if no compositing were done. A theoretical justification of these techniques is given in Appendix C of Lucas et al.[1]

Tables 69 and 70 display the statistical summary of the TOCl concentrations measured in the pilot study.

Chemical Analysis Measurement Errors

To assess the measurement errors in the chemical analysis, a method of standard additions was employed. Known amounts of two surrogate compounds, d_8-naphthalene and d_{12}-chrysene, were added to the composited specimens before the chemical analysis. The mean percent recoveries of the surrogate compounds and their CVs are given in Tables 71 and 72.

If the percent recoveries in these tables are indicative of the recovery rate for TOCl, then the concentrations of TOCl are underestimated. This underestimation would be greater for the specimens from Chicago than those from Ames. However, the summary statistics reported in Table 66 and 67 above are not adjusted for the percent recovery. Biases of this type can affect the true confidence of a nominal 95% confidence interval. For example, in Table 68 the mean percent recovery of the surrogate compounds of the flue gas inlet is 59%. If this indicates a negative bias in estimating the true mean concentration of TOCl of 41%, the true confidence of the nominal 95% confidence interval can be estimated using Table 73. To calculate the ratio of the bias (BIAS) and standard error (SE), use

$$\text{BIAS/SE} = 41/(49/\sqrt{19}) = 3.7 \ ,$$

where 41 is the absolute percent bias, 49 is the CV in Table 69, and 19 is the number of specimens analyzed. Table 73 indicates the true confidence of the nominal 95% confidence interval in Table 66 is less than 6%. Table 73 also includes the impact of other levels of bias (relative to the SE) on the true confidence of a nominal 95% confidence interval.

TABLE 69. SUMMARY STATISTICS FOR TOTAL ORGANIC CHLORINE CONCENTRATION DATA FROM AMES, IOWA

Media (units)	Number of specimens	Mean	Coefficient of variation (%)	Degrees[a] of freedom	Nominal 95%[b] confidence interval
Gaseous (ng/dscm)					
Flue gas inlet	19	562	49	18	(426, 698)
Flue gas outlet	11	632	85	10	(254, 1,010)
Ambient air	20	*			
Solid (ng/g)					
Fly ash	90	8.3	536	50	(-1.0, 17.6)
(c)	(89)	3.6	81	(49)	(2.9, 4.2)
Bottom ash	88	58.6	183	50	(35.1, 82.1)
Coal	11	4.4	23	5	(3.5, 5.3)
Refuse-derived fuel	62	11,900	116	36	(8,342, 15,470)
Liquid (ng/liter)					
OW[d]	91	664	70	51	(570, 760)
Quench water influent	6	373	33	5	(231, 514)
Well water	3	54	32	2	(1.4, 107)

a Number of independent chemical analyses minus one.

b Nominal value based on normal probability distribution theory.

c Numbers in ( ) are estimates excluding the maximum value of 210 ng/g. This value is 21 times larger than the next largest value. Both sets of summary statistics are included to illustrate the impact of the one extreme value on the estimates.

d Bottom ash hopper quench water overflow.

* Measured values in field specimens not significantly different from blanks.

Table 70. SUMMARY STATISTICS FOR TOTAL ORGANIC CHLORINE CONCENTRATION DATA FROM CHICAGO NW

Media (units)	Number of specimens	Mean	Coefficient of variation (%)	Degrees[a] of freedom	Nominal 95%[b] confidence interval
Gaseous (ng/dscm)					
Flue gas inlet	11	2,200	34	10	(1,698, 2,702)
Flue gas outlet	11	3,220	109	10	(862, 5,578)
(c)	(10)	(2,190)	(36)	(9)	(1,330, 3,040)
Ambient air	12	1.67	64	11	(-.68, 4.02)
Solid (ng/g)					
Fly ash	72	93.6	85	52	(71.7, 115.6)
Combined ash	67	9.9	162	50	(5.8, 13.9)
Refuse	61	902	251	50	(283.8, 1,520)
Liquids (ng/liter)					
City tap water	4	30	0	*	*

* Not calculated because there was no variability in the data.

a Number of independent chemical analyses minus one.

b Nominal value based on normal probability distribution theory.

c Numbers in ( ) are estimates excluding the maximum value of 13,500 ng/dscm. This value is 4 times larger than the next largest value. Both sets of summary statistics are included to illustrate the impact of the one extreme value on the summary statistics.

TABLE 71. SUMMARY OF SURROGATE COMPOUNDS PERCENT RECOVERY FOR SPECIMENS FROM AMES, IOWA

Media	d_8-Naphthalene[b]			d_{12}-Chrysene		
	No. of analyses	Mean % recovery	Coefficient of variation (%)	No. of analyses	Mean % recovery	Coefficient of variation (%)
Gaseous						
Flue gas inlet	18	56	45	19	71	26
Flue gas outlet	11	47	25	11	86	14
Solid						
Fly ash	51	44	56	51	96	24
Bottom ash	42	55	36	49	85	37
Coal	6	90	18	6	90	19
Refuse-derived fuel	37	65	22	37	111	25
Liquid						
OW[a]	40	51	54	48	88	29
Quench water influent	6	69	25	6	111	16
Well water	2	66	1	3	88	20

a Bottom ash quench water overflow.

b Specimens that were inadvertently evaporated to dryness were excluded.

TABLE 72. SUMMARY OF SURROGATE COMPOUND PERCENT RECOVERY FOR SPECIMENS FROM CHICAGO, NW

Media	d_8-Naphthalene			d_{12}-Chrysene		
	Number of analyses	Mean percent recovery	Coefficient of variation (%)	Number of analyses	Mean percent recovery	Coefficient of variation (%)
Gaseous						
Flue Gas Inlet	11	37	84	11	74	48
Flue Gas Outlet	11	27	98	11	62	82
Ambient Air	12	31	75	12	51	88
Solid						
Fly Ash	53	26	68	52	36	61
Combined Ash	33	35	57	33	22	105
Refuse	44	9	51	44	12	193
Liquid						
City Tap Water	3	27	131	3	13	92

TABLE 73. VALIDITY OF CONFIDENCE STATEMENTS FOR SELECTED LEVELS OF BIAS

BIAS/SE[a]	True confidence level* for the $\bar{x} \pm 1.96$ SE interval
0	0.95
0.5	0.92
1.0	0.83
1.5	0.68
2.0	0.48
2.5	0.29
3.0	0.15
3.5	0.06
4.0	0.02

* Calculated according to the integral of the

$$\int_{-1.96 + \text{BIAS/SE}}^{1.96 + \text{BIAS/SE}} \frac{1}{2^{\frac{1}{2}}} e^{-\frac{1}{2}x^2} dx$$

a BIAS/SE is used because the true confidence depends on the relative magnitude of the bias with respect to the SE, not the absolute magnitude. Here, BIAS denotes the absolute average deviation of the estimate from the true value and SE denotes the standard error of the estimate and is equal to the standard deviation (s) divided by the square root of the sample size ($\sqrt{n}$).

Table 74 summarizes the estimates of the CVs ($S/\bar{X}$) for both the sampling and measurement (as indicated by the surrogate recovery data) component. One should note that the measurement CVs for Ames are uniformly less than those for Chicago. In fact, for some sampling locations at Chicago NW, the measurement component dominates the total variability giving negative estimates of the sampling component. This is not unexpected for the ambient air and city tap water because at these two locations one would expect the media to be rather homogeneous. However, this is unexpected at the flue gas inlet.

SECOND TIER SUMMARY

In the second tier of chemical analysis the concentrations of many compounds were measured. Because of the expense at this level of chemical analysis, much compositing of specimens was done before the analyses were performed. At Ames, five pairs of days were randomly selected. For each sampling location, all specimens collected during the pair of days were composited for one chemical determination. This gave a total of five independent chemical determinations in this tier for each sample location from Ames except RDF, where only four chemical determinations were performed. At Chicago, three sets of three days were randomly selected. For the selected sampling locations, all specimens collected during the three days were composited for one chemical determination. This gave a total of three independent chemical determinations in this tier for the selected sample locations at Chicago.

To statistically summarize the second tier data, the arithmetic mean ($\bar{X}$) and CV ($S/\bar{X}$) were calculated for the concentration measurements. Also, to estimate the mass flow rates, the variable Y_i was defined as

$$Y_i = r_i \, X_i \, ,$$

where X_i is the concentration for the i^{th} chemical determination and r_i is the mass flow rate associated with the i^{th} chemical determination. The arithmetic mean $\bar{Y}$ and CV ($S/\bar{Y}$) were calculated to summarize the flow rates.

In calculating the mean concentrations and flow rates, all trace values were assumed to be zero. This will result in an underestimate of the true values. The number of quantifiable values are also included in the summaries. The magnitude of underestimation resulting from substituting zero for trace values depends upon the number of traces and the levels of quantifiable values compared to the minimum quantifiable level.

Because of the relatively few composites measured for each compound, the presence of trace values, and the relative large variability in the data (large CVs), no confidence intervals are included in the data summaries.

Table 74. SUMMARY OF COEFFICIENT OF VARIATION* FOR THE PILOT STUDY

Media	Ames Sampling	Ames Measurement	Chicago, NW Sampling	Chicago, NW Measurement
Gaseous				
Flue gas inlet	42	25	c	68
Flue gas outlet	84	13	85	68
Ambient air	a	a	c	87
Solid				
Fly ash	535 (78)[b]	24	56	64
Bottom ash	179	38		
Combined ash			143	76
Coal	12	19		
Refuse-derived fuel	114	18		
Refuse			194	159
Liquid				
OW	58	38		
Quench water influent	17	28		
City tap water			c	132

a Not calculated because specimen amounts were not significantly different from blanks.

b Number in ( ) are estimates excluding the maximum value of 210 ng/g. This value is 21 times larger than the next largest value. Both summary statistics are included to illustrate the impact of the one extreme value on the estimate.

c The estimates of these values were negative and were excluded because the CV must be non-negative.

* The measurement CVs presented above are a weighted average of the CVs in Tables 68 and 69. They were calculated by $CV = (S_8^2 + S_{12}^2)^{\frac{1}{2}}/(\bar{X}_8 + \bar{X}_{12})$, where the subscripts 8 and 12 denote d_8-naphthalene and d_{12}-chrysene, respectively.

The second tier chemical analysis data is summarized in Tables 75 through 81. These tables include summaries of the primary input and emissions media at Ames. These are coal, refuse-derived fuel, combustion air, flue gas inlet, flue gas outlet, fly ash and bottom ash. The secondary input and emission media, bottom ash hopper quench water influent, well water, and bottom ash water quench water overflow, were excluded because of the sparsity of the data. These tables also include the summaries for the flue gas inlet and outlet from Chicago. The combustion air, combined ash, and fly ash are excluded because of the sparsity of the data. No second tier chemical analysis was done on the refuse from Chicago.

TABLE 75. SUMMARY STATISTICS FOR COMPOUNDS QUANTITATED IN PRIMARY INPUT MEDIA AT AMES, IOWA

Compound	Coal					Refuse-derived fuel					Combustion air				
	Number of detections	Concentration (ng/g)		Input rate (mg/hr)		Number of detections	Concentration (ng/g)		Input rate (mg/hr)		Number of detections	Concentration (ng/g)		Input rate (mg/hr)	
		Mean	CV (%)	Mean	CV (%)		Mean	CV (%)	Mean	CV (%)		Mean	CV (%)	Mean	CV (%)
Phenanthrene	5	11,830	41	166,000	43	4	1,030	25	2,700	41	5	0.56	44	0.083	48
Anthracene	5	2,180	52	30,800	53	1	74	200	202	200	3	0.10	92	0.016	95
Fluoranthene	5	2,050	56	28,800	56	4	440	83	875	50	5	0.65	37	0.10	42
Pyrene	5	2,440	57	34,600	57	4	411	28	1,180	53	5	0.67	42	0.10	45
Chrysene	5	679	69	9,720	71	1	109	200	300	200	5	0.41	28	0.06	31
Benzo[a]pyrene	0					0					5	0.10	41	0.066	182
Indeno[1,2,3-c,d]-pyrene	0					0					2[b]	0.004	224	0.001	224
Benzo[g,h,i]-perylene	0					0					4[c]	0.02	224	0.003	224
Dichlorobenzene	0					4	863	52	2,650	79	0				
1,2,4-Trichloro-benzene	0					0					3[d]	0.006	149	0.0009	145
Hexachloro-butadiene	0					0					2[b]	0.004	224	0.0005	224
Pentachloro-phenol	0					2	498	126	1,250	133	2[b]	0.01	224	0.002	224
Pentachlorobi-phenyl	0					2	a				0				
Phenol	5	15,360	68	217,800	68	0					5	1.7	54	0.25	51
Naphthalene	5	1,760	34	24,800	35	4	10,300	166	28,400	164	5	0.25	30	0.037	33
Flourene	5	4,500	38	63,200	39	4	438	28	1,220	51	4	0.19	67	0.029	69
Benzo[a]an-thracene	0					0					5	0.41	40	0.063	44
Benzofluoran-threne	5	630	68	8,960	71	0					5	0.58	19	0.087	24
Acenaphthene	5	1,220	33	17,100	32	4	300	200	800	200	0				
Acenaphthylene	5	374	38	5,220	37	0					0				

* CV denotes the coefficient of variation and is calculated by dividing the standard deviation by the mean.

a Only trace values were detected, hence no quantification was attempted.

b One specimen contained a quantifiable level and one a trace. The trace is always assumed to be zero to calculate the mean and CV.

c One specimen contained a quantifiable level and three were traces.

d Two specimens contained a quantifiable level and one a trace.

TABLE 76. SUMMARY STATISTICS FOR COMPOUNDS QUANTITATED IN GASEOUS EMISSIONS AT AMES, IOWA

Compound	Flue gas inlet: Number of detections	Flue gas inlet: Concentration (ng/g) Mean	Flue gas inlet: Concentration (ng/g) CV (%)	Flue gas inlet: Emission rate (mg/hr) Mean	Flue gas inlet: Emission rate (mg/hr) CV (%)	Flue gas outlet: Number of detections	Flue gas outlet: Concentration (ng/g) Mean	Flue gas outlet: Concentration (ng/g) CV (%)	Flue gas outlet: Emission rate (mg/hr) Mean	Flue gas outlet: Emission rate (mg/hr) CV (%)
Phenanthrene	5	438	48	134	51	5	309	54	66	74
Anthracene	5	76.4	24	22	25	5	65.4	25	20	28
Fluoranthene	5	126	55	39	60	5	68.2	64	20	60
Pyrene	5	422	62	130	68	5	170	67	50	60
Chrysene	5[a]	8.8	129	2.6	125	5[c]	0.54	224	0.15	224
Benzo[a]pyrene	5	57.4	72	18	74	3[d]	8.2	151	2.0	143
Benzo[g,h,i]-perylene	0					3	6.0	154	1.8	153
Dichlorobenzene	3	25.8	125	7.8	126	2	1.7	142	0.50	141
1,2,4-Trichloro-benzene	3	69.6	108	20	108	3	39	139	12	140
Hexachloro-butadiene	1	20.6	224	6.0	224	0				
Tetrachloro-benzene	1[b]					0				
Pentachloro-phenol	1	4.8	224	1.4	224	0				
Phenol	5	7,260	53	2,160	54	5	5,860	30	1,780	33
2,4-Dimethy-phenol	0					4	1,120	67	336	63
Naphthalene	5	974	50	298	53	5	486	62	146	58
Fluorene	1	24	224	6.8	224	0				
Benz[a]anthra-cene	1	1.4	224	0.44	224	0				
Benzofluoran-threne	2	5.4	145	1.1	140	5[a]	5.6	81	1.7	80
Benzo[e]pyrene	0					1	5.8	224	1.8	224
Acenaphthylene	2	8.8	138	2.8	135	0				
Trichloro-benzene	0					3	27	116	8.7	123

* CV denotes the coefficient of variation and calculated by dividing the standard deviation by the mean.

a Four specimens contained quantifiable levels and one a trace. All trace values are assumed to be zero when calculating the mean and CV.

b One specimen contained a trace.

c One specimen contained a quantifiable level and four contained traces.

d Two specimens contained quantifiable levels and one a trace.

TABLE 77. SUMMARY STATISTICS FOR COMPOUNDS QUANTITATED IN SOLID EMISSIONS AT AMES, IOWA

Compound	Fly ash					Bottom ash				
	Number of detections	Concentration (ng/g)		Emission rate (mg/hr)		Number of detections	Concentration (ng/g)		Emission rate (mg/hr)	
		Mean	CV (%)	Mean	CV (%)		Mean	CV (%)	Mean	CV (%)
Phenanthrene	5[a]	0.2	61	0.2	71	5	193	100	75	96
Anthracene	0					2	31	183	12	169
Fluoranthrene	0					4	108	177	40	170
Pyrene	0					5	106	168	39	162
Chrysene	1	0.1	224	0.1	224	1	34	224	12	224
Dichloro-benzene	1	0.01	224	0.02	224	3[b]	4.8	224	1.9	224
Phenol	3	158	102	190	102	5	1,094	55	420	92
2,4-Dimethyl-phenol	0					4[c]	7.0	167	2.7	176
Naphthalene	2	0.07	137	0.08	137	5[a]	103	146	42	142
Fluorene	0					1	3	224	1.5	224
Acenaphthene	0					1	0.2	224	0.11	224
Acenaphthylene	0					5	87	55	25	66

* CV denotes the coefficient of variation and is calculated by dividing the standard deviation by the mean.

a Four specimens contained quantifiable levels and one a trace. Trace values are always assumed to be zero when calculating the mean and CV.

b One specimen contained a quantifiable level and two a trace.

c Two specimens contained quantifiable levels and two a trace.

TABLE 78. SUMMARY OF TOTAL INPUT AND EMISSIONS FROM AMES, IOWA

Compound	Total input rate (mg/hr)		Total emission rate (mg/hr)	
	Mean	CV (%)	Mean	CV (%)
Phenanthrene	169,000	42	141	62
Anthracene	31,000	53	32	66
Fluoranthene	29,700	54	60	115
Pyrene	35,800	55	89	79
Chrysene	10,020	69	12.2	219
Benzo[a]pyrene	0.066	182	2.0	143
Indeno[1,2,3-c,d]pyrene	0.001	224	nd	
Benzo[g,h,i]perylene	0.003	224	1.8	153
Dichlorobenzene	2,650	79	2.4	178
1,2,4-Trichlorobenzene	0.0009	145	12	140
Hexachlorobutadiene	0.0005	224	nd	
Tetrachlorobenzene	nd		nd	
Pentachlorophenol	1,250	133	nd	
Pentachlorobiphenyl	tr		nd	
Phenol	217,800	68	2,390	31
2,4-Dimethylphenol	nd		339	63
Naphthalene	53,200	89	188	55
Fluorene	64,400	38	1.5	224
Benz[a]anthracene	.063	44	nd	
Benzofluoranthrene	8,960	71	1.7	80
Benzo[e]pyrene	nd		1.8	224
Acenaphthene	17,900	32	0.11	224
Acenaphthylene	5,220	37	25	66
Trichlorobenzene	nd		8.7	123

nd denotes not detected.

tr denotes trace.

* CV denotes coefficient of variation and is calculated by dividing the standard deviation by the mean.

TABLE 79. SUMMARY STATISTICS FOR COMPOUNDS QUANTITATED IN GASEOUS EMISSIONS FROM CHICAGO

	Flue gas inlet					Flue gas outlet				
		Concentration (ng/g)		Emission rate (mg/hr)			Concentration (ng/g)		Emission rate (mg/hr)	
Compound	Number of detections	Mean	CV (%)	Mean	CV (%)	Number of detections	Mean	CV (%)	Mean	CV (%)
Phenanthrene	3	60	87	5.4	90	3	217	53	18	52
Fluoranthene	3	52	98	4.6	98	3	39	31	3.3	33
Pyrene	3	166	75	14	76	3	87	10	7.5	10
1,3-Dichloro-benzene	3	93	70	8.4	71	0				
1,4-Dichloro-benzene	3	69	69	5.9	69	0				
1,2-Dichloro-benzene	3	93	69	8.0	69	0				
1,2,3-Trichlo-robenzene	3	83	68	7.1	69	3	85	66	6.9	64
1,2,4-Trichlo-robenzene	3	363	54	30	55	3	327	62	28	62
1,3,5-Trichlo-robenzene	3	297	63	26	66	3	277	57	24	60
Tetrachloro-benzene	3	957	49	82	49	3	940	43	81	43
Hexachloro-benzene	3	50	90	4.5	92	3	139	78	12	80
Dichlorophenol	3	330	61	25	51	3	383	56	33	54
Trichloro-phenol	3	1,220	64	105	64	3	1,500	24	126	25
Tetrachloro-phenol	3	1,300	63	111	64	3	1,430	21	122	19
Pentachloro-phenol	2	65	101	5.5	101	3	260	57	22	55
Dibenzofuran	3	46	77	3.9	76	3	102	36	8.5	31

* CV denotes the coefficient of variation and is calculated by dividing the standard deviation by the mean.

TABLE 80. SUMMARY OF FLUE GAS EMISSIONS OF POLYCHLORINATED BIPHENYL ISOMERS FROM AMES, IOWA

Compound	Concentration (ng/dscm) Mean	CV (%)	Emission rate (mg/hr) Mean	CV (%)
Dichlorobiphenyl	nd			
Trichlorobiphenyl	1.5	185	0.48	189
Tetrachlorobiphenyl	2.9	63	0.94	64
Pentachlorobiphenyl	9.0	87	2.8	80
Hexachlorobiphenyl	5.1	104	1.7	104
Heptachlorobiphenyl	0.6	224	0.2	224
Decachlorobiphenyl	0.6	224	0.2	224
Total Chlorobiphenyl	19.4	46	6.1	47

* CV denotes the coefficient of variation and is calculated by dividing the standard deviation by the mean.

TABLE 81. SUMMARY OF FLUE GAS EMISSIONS OF POLYCHLORINATED BIPHENYLS, DIBENZO-p-DIOXINS, AND DIBENZOFURANS FROM CHICAGO NW

Compound	Concentration (ng/dscm) Mean	CV (%)	Emission rate (mg/hr) Mean	CV (%)
Dichlorobiphenyl	17.3	114	4.4	113
Trichlorobiphenyl	16.0	109	4.1	108
Tetrachlorobiphenyl	6.2	96	1.6	95
Pentachlorobiphenyl	2.6	68	1.6	67
Total chlorobiphenyl	42.1	105	10.7	104
Total trichlorodibenzo-p-dioxins	13	16	1.1	19
Total trichlorodibenzofurans	300	15	27	11
Total tetrachlorodibenzo-p-dioxins	6.3	14	0.53	15
Total tetrachlorodibenzofurans	90	7	7.6	5
Total hexachlorodibenzo-p-dioxins	16	25	1.4	25
Total hexachlorodibenzofurans	62	33	5.3	32
Total heptachlorodibenzo-p-dioxins	7.6	4	0.65	4
Total heptachlorodibenzofurans	7.5	6	0.64	5
Octachlorodibenzo-p-dioxin	2.5	12	0.22	12
Octachlorodibenzofuran	0.60	22	0.05	21

* CV denotes the coefficient of variation and is calculated by dividing the standard deviation by the mean.

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APPENDIX A

TRW FIELD TEST REPORT FOR THE AMES MUNICIPAL ELECTRIC SYSTEM, UNIT NO. 7

PILOT TEST PROGRAM
AMES MUNICIPAL POWER PLANT
UNIT NO. 7

TRW ENVIRONMENTAL ENGINEERING DIVISION
TRW, INC.

28 April 1980

EPA Contract 68-02-2197

EPA Project Officer: Michael C. Osborne

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, N.C. 27711

CONTENTS

FIGURES

TABLES

1. INTRODUCTION

This document describes the sampling and monitoring activities at the Ames Municipal Power Plant, boiler unit No. 7. The sampling and field measurement work performed was part of an overall pilot scale test program sponsored by the Office of Pesticides and Toxic Substances in cooperation with the Office of Research and Development, of the U.S. Environmental Protection Agency.

The ultimate objective of the pilot scale test program is to develop an optimum sampling and analysis protocol to characterize polychlorinated organic compounds which may be emitted in trace quantities through conventional combustion of fossil fuels and refuse. The genesis of the program is an industrial study by Dow Chemical Company and two groups of European investigators reporting emissions of polychlorinated dibenzo-p-dioxins (PCDD), dibenzofurans (PCDF) and biphenyls (PCB) from stationary conventional combustion sources.

The immediate objective of the sampling and field measurements program (for a fossil-fuel 17% RDF-fired utility boiler) is the specification of procedures and equipment to obtain sufficient multimedia samples for the subsequent analytical protocol, and to satisfy the program statistical design requirements. In this respect, the TRW Environmental Engineering Division of TRW, Inc., was one of three contractors participating in the overall EPA program. These contractors, their key individuals and respective roles are:

1. Research Triangle Institute
   Research Triangle Park, North Carolina
   Statistical design of the overall test program
   Mr. R. M. Lucas, Task Manager
2. TRW Environmental Engineering Division, TRW, Inc.
   Redondo Beach, California
   Acquisition of samples and field measurements
   Mr. B. J. Matthews, Project Manager
3. Midwest Research Institute
   Kansas City, Missouri
   Laboratory analysis of all field samples
   Dr. C. L. Haile, Task Manager

The sampling was oriented toward acquiring multimedia samples for organic compound analysis by Midwest Research Institute (MRI). Compounds of particular interest included:

Benzo [a] pyrene	Chrysene
Pyrene	Indeno [1,2,3-cd] pyrene
Fluoranthene	Benzo [g,h,i] perylene
Phenanthene	Anthracene

In addition, MRI is to make a determination of total organic chlorine emissions from the acquired samples. Potentially, selected samples are to be analyzed for dibenzo-p-dioxins, dibenzofurans and biphenyls.

Instrumentation for on-line combustion gas stream monitoring was part of the test program. In addition, utility boiler process information (including RDF data) was also gathered. This information together with the monitoring data were acquired to assist in evaluating and interpreting chemical analysis results.

This report contains all the field data for the Ames Municipal Power Plant pilot test program conducted in March 1980. Data provided include the following:

- Chlorinated hydrocarbon collection using a modified EPA Method 5 train and Method 5 sampling methodology,
- Gas velocities using EPA Method 2,
- Continuous monitoring for CO_2, O_2, and CO and THC,
- Particulate collection for inorganic analysis utilizing EPA Method 5.
- Process data.

The test program followed was described in the Pilot Test Program, Ames Municipal Power Plant, Unit No. 7 site test plan. Deviations from this program are documented and explained in their respective sections of this report.

2. SUMMARY

2.1 Sampling and Analysis

The field test activity took place from February 25, 1980 to March 28, 1980. All required tests were completed and all recovered samples were sent to Southwest Research Institute (SRI) for analysis. MRI had subcontracted this part of their assignment to SRI.

A summary of tests conducted including any significant commentary is presented in Table 2-1. A summary of the reduced data on a daily basis as calculated from the field data sheets is presented in Table 2-2. Data listed are corrected to standard conditions, i.e., 20°C and a barometric pressure of 29.92 inches mercury.

Sampling and calibration procedures are described in Sections 4, 5 and 6. Hourly data is provided in the appendices. Appendix A contains continuous monitoring data; Appendix B contains field data; and Appendix C contains the solid and liquid sampling schedule.

2.2 Process Data

Process data was monitored on an hourly basis. A summary of the averaged daily process data is provided in Table 2-3. The process data was also averaged for the time duration of actual testing performed. This data is presented in Table 2-4.

The process data gathered indicated that the operating conditions fluctuated in patterns related to the amount of electricity generation demand placed on the boiler, and on the type of fuel being burned to meet that demand. Overall fluctuation consisted of two components. The first component was the Daily variation - the load peaked in the afternoon and fell a minimum before dawn. The second type of variation was caused by sudden operational changes, which was due to reduced power generation for various reasons such as the buying of cheaper power from a private utility, or the reduction in flow of RDF to the boiler.

TABLE 2-1. DAILY ORGANIC SAMPLING SUMMARY

Date 1980	Test No.	Sampling locations	Test comments
3/2	1	Inlet North	Test started at 1120 and ran for 520 minutes. Low volume collected due to high leak rate at end. Volumes corrected for leak rate. If leak occurred over the entire test period then, at worst case, the results are 50% low. Test quality fair. (Port 13 to be dropped due to absence of flow).
		Inlet South	Test started at 1125 and ran for 520 minutes. Low volume collected trying to stay within 12 hour time limit. Test quality good. (Port 1 to be dropped due to absence of flow.)
		Outlet Ports 2 and 3	Loss of 3 hours start due to freezing of pumps. Stopped test 360 minutes into test due to freezing of impingers. All of Port 3 traversed and only 1/2 of Port 2 - low volume collected but test quality is good due to the evenness of flow in stack.
		Outlet - Ports 1 and 4	Started at 1200, ran for 390 minutes - stopped due to freezing of impingers and equipment - low volume due to stoppage - impingers backed up due to freezing of impinging solutions. Resin in impingers 1 and 2 also due to freezing. Test quality fair.
		Hi Volume Sampler	Test started at 1115 and off 1939. Test quality good.
		Continuous monitors	Started at 1300 hrs and off at 1930 - lost start time due to gas conditioner being frozen. Unable to maintain heat line temperature due to cold weather and moisture condensing in heat line possibly scrubbing hydrocarbons, hydrocarbon results low. Test quality good. Hydrocarbon fair.
3/3	2	Inlet North	Dropped port 13 from test. Test started at 0925 and ran for 550 minutes. At 250 minutes nozzle was found to be facing in the wrong direction, reversed nozzle direction continued test. Particulate catch and size distribution will be approximately 25% low. No effect on Battelle trap. Switched to smaller diameter nozzle to maintain isokinetic flow rate. Test quality for particulate fair, for gas good.
		Inlet Sou..	Test started at 0945 and ran for 550 minutes. Switched to smaller diameter nozzle to maintain isokinetic flow rate. Test quality good. Dropped port 1 from test.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test comments
3/3	2	Outlet Ports 2 and 3	Test started at 0945 and ran for 480 minutes. Test quality good.
		Outlet Ports 1 and 4	Test started at 0945 and ran for 480 minutes. Test quality good.
		Hi Volume Sampler	Started at 1032 ended at 1915. Test quality good.
		Continuous Monitors	Started at 0930 ended at 1900. Test quality good except hydro-Carbon values being low and hydrocarbon quality fair.
3/4	3	Inlet North	Test started at 0905 and ran 417 minutes. At 75 minutes Battelle trap plugged and replaced with new one. At 250 minutes Battelle trap replaced due to leak and points (total of 2) retested. Switched to 10 minutes a point traverse rather than 25 minutes to complete test. All 3 Battelle traps should be composited due to lower volume sampled during 10 minute/point traverse. Test quality fair - total volume 50% of required.
		Inlet South	Test started 0900 ran for 550 minutes. Test quality good.
		Outlet Ports 2 and 3 Ports 1 and 4	Test started 0938 ran for 15 minutes. Cancelled due to snow and icy conditions. No samples retained.
		Hi Volume Sampler	Started at 0930 ended at 1800. Filter covered with snow. Test quality fair due to snow blanket.
		Continuous Monitors	Gas conditioner frozen until 1230. Started at 1230 ended at 1800. Test quality good. Hydrocarbon results fair.
3/5	4	Inlet North	Test started 0900 and ran for 560 minutes. Test quality good.
		Inlet South	Test started at 0900 and ran for 550 minutes. Test quality good.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/5	4	Outlet - All Points	Cancelled per instructions of EPA until 3/13/80.
		Hi Volume Sampler	Started at 1025 ended at 1940. Test quality good.
		Continuous Monitors	Started at 0945 ended at 1150 am. Stopped due to freeze up of lines. Test quality good for data collected.
3/6	5	Inlet North	Test started at 0850 and ran for 770 minutes. At 11 minutes into test Battelle trap plugged and was replaced. Test restarted from beginning. Test quality good.
		Inlet South	Test started at 0840 and ran for 770 minutes. Test quality good.
		Hi Volume Sampler	Test started at 0852 and ended at 2220 Hrs, Test quality good.
		Continuous Monitors	Only inlet tested due to outlet freeze up. Test started at 1230 and ended 2045. Two hours late start and shut down 2 hours early to overlap sampling time. Test quality good. Hydrocarbons still fair.
3/7	6	Inlet North	Test started at 0930 and ran for 770 minutes. Due to increased amount of water collected, impingers needed changing and during changeout resin flowed into first impinger. Trap replaced and test resumed. Test quality good.
		Inlet South	Test started at 0850 and ran for 770 minutes. Test quality good.
		Hi Volume Sampler	Test started at 1038 and ended at 2225. Construction welding going on nearby. Test quality expected to be good.
		Continuous Monitors	Test started at 1315 hrs and shut down at 2100 hours. Overlap of inlet test. Test quality good. Hydrocarbons fair.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/8	7	Inlet North	Test started at 0855 and ran for 770 minutes. 10 minute power failure - no problems caused by this. Test quality good.
		Inlet South	Test started 0840 and ran for 770 minutes. 30 minute power failure on this side - no problems. Probe broken at end of test during removal from port. Approximately 2% of probe catch lost. Test quality good.
		Hi Volume Sampler	Test started at 1335 and ended at 2330. Test quality good.
		Continuous Monitors	Test started at 1215 and ended 2030 hrs. Data not taken at inlet during 1300 hrs. to 1400 hours due to change out of probe filters. Test quality good. Hydrocarbon data fair.
3/9	8	Inlet North	Test started at 0900 and ran for 770 minutes. Point 8D was run for 70 minutes to correct sampling time lost on point 11A not being sampled after nozzle change. Test quality good.
		Inlet South	Test started at 0830 and ran for 770 minutes. Changed to larger nozzle to maintain isokinetic flow rate. Due to severe leak, that occurred during last portion of test, this test is questionable.
		Hi Volume Sampler	Test started at 0908 and ended at 2320 hrs. Test quality good.
			Test started at 1245 and ended at 2320 hrs. Test quality good. Hydrocarbon data fair.
3/10	9	Inlet North	Test started at 0825 and ran for 140 minutes. Probe found to be broken and test restarted, no samples retained. Restarted at 1155 ran until 1745. Test stopped, with only 1/2 the duct traversed, due to cold, freeze ups and power failures. Resin, cyclone, filter, 1st impinger saved. Test quality fair.
		Inlet South	Test started at 0810 ran for 515 minutes. Power failures and freeze ups happening cancelled test with the North side. No solutions retained from South due to H_2O_2 backup into all impingers - resin, cyclone and filters retained. Test quality fair.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/10	9	Hi Volume Sampler	Test started at 1050 and ended at 2235 hrs. Test quality good.
		Continuous Monitors	Test started at 1130 am and ended at 1730 hours. Stopped with inlet. Test quality good. Hydrocarbon fair.
3/11	10	Inlet North	Test started at 0825 and ran 770 minutes. Battelle trap replaced at 220 minutes. 2nd Battelle trap resin broke through and was replaced. 3 Battelle traps used. Test quality good.
		Inlet South	Test started at 0830 and ran for 770 minutes. Filter clogged and replaced. Test quality good.
		Hi Volume Sampler	Test started at 0920 and ended at 2375 hrs. Test quality good.
		Continuous Monitors	Test started at 1200 and ended at 2030 hrs. Test quality good. Hydrocarbon fair.
3/12	11	QA Test	Test cancelled after 240 minutes - a leak was found at one of the probe tips-unable to repair and no sample had been drawn through the train.
		Hi Volume Sampler	Test started at 0955 stopped at 1955. Test quality good.
		Continuous Monitors	Test started at 0830 stopped at 1430 hrs. Test quality good. Hydrocarbon fair.
3/13	12	Inlet North	Test started at 0915 and ran for 770 minutes. Power failures occurred-no effect on test. Filter changed due to clogging. Test quality good.
		Inlet South	Test started at 0835 and ran for 770 minutes. Power failure occurred no effect on test. Test quality good.
		Outlet Ports 2 & 3	Test started at 1210 and ran for 560 minutes. Lost startup due to freezing of equipment and traps - thawing took 1-2 hours. Test quality good.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/13	12	Outlet Ports 1 & 4	Test started at 1125 and ran for 296 minutes. Stopped due to continual freezing of train components. One port completely traversed. Only 16 minutes of the second. Test quality - fair to poor.
		Hi Volume Sampler	Test started at 0950 and ended 0130. Test quality good.
		Continuous Monitors	Test started at 1145 and ended at 1845 hours. Test quality good. Hydrocarbons fair.
3/14	13	Inlet North	Test started 0845 and ran for 770 minutes. Filter clogged and was replaced. Test quality good.
		Inlet South	Test started at 0840 and ran for 770 minutes. Test quality good.
		Outlet Ports 2 & 3	Test started at 0945 and ran for 560 minutes. Test quality good.
		Outlet Ports 1 & 4	Test started at 1010 and ran for 560 minutes. Probe broken during port change - replaced and test continued. Test quality good.
		Hi Volume Sampler	Test started at 0905 and ended at 2355 hrs. Test quality good.
		Continuous Monitors	Test started at 0900 and ended at 2045 hrs. No data from 1330 to 1515 hrs due to feeeze up. Test quality good. Hydrocarbon fair.
3/15	14	Inlet-North	Test started at 0909 and ran for 770 minutes. Test quality good.
		Inlet South	Test started at 0905 and ran for 770 minutes. Test quality good.
		Outlet Ports 2 & 3	Test started at 0958 and ran for 560 minutes. Test quality good.
		Outlet Ports 1 & 4	Test started at 1025 and ran for 560 minutes. Test quality good.
		Hi Volume Sampler	Test started at 0850 and ended at 2341 hrs. Test quality good.
		Continuous Monitors	Test started at 0845 and ended at 2000 hrs. Test quality good. Hydrocarbon data fair.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/17	15	Inlet North	Test started at 0849 and ran for 770 minutes. Test quality good.
		Inlet South	Test started at 0900 and ran for 770 minutes. Test quality good.
		Outlet Ports 2 & 3	Test started at 1000 and ran for 560 minutes. Test quality good.
		Outlet Ports 1 & 4	Test started at 1010 and ran for 560 minutes. Test quality good.
		Hi Volume Sampler	Test started at 0926 and ended at 0020 hrs. Test quality good.
		Continuous Monitors	Test started at 1030 and ended 2015 hrs. Test quality good. Hydrocarbon data fair.
3/18	16	Inlet North	Test started at 0939 and ran for 770 minutes. Test quality good.
		Inlet South	Test started at 0900 and ran for 770 minutes. Test quality good.
		Outlet Ports 2 & 3	Test started at 0930 and ran for 560 minutes. Test quality good.
		Outlet Ports 1 & 4	Test started at 0940 and ran for 560 minutes. Probe broke during port change - switched to 5 ft glass probe to traverse first 6 points of second part. After 10 ft probe of ports 2 and 3 had been recovered and cleaned, it was sent to the stack to finish remaining 2 points of ports 1 and 4. Test quality good.
		Hi Volume Sampler	Test started at 1033 and ended 0200 hours. Test quality good.
		Continuous Monitors	Test started at 0845 and ended at 1945 hrs. Test quality good. Hydrocarbon data fair.
3/19	17	Inlet North	Test started at 0859 and ran for 770 minutes. Test quality good.
		Inlet South	Test started at 0843 and ran for 770 minutes. Test quality good.
		Outlet Ports 2 & 3	Test started at 0945 and ran for 560 minutes. Test quality good.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/19	17	Outlet Ports 1 & 4	Test started at 0940 and ran for 560 minutes. Test started with 5 foot probe until new 10 ft arrived. Finished Test with 10 ft probe. Test quality good.
		Hi Volume Sampler	Test started at 1006 and ended at 0120 hrs. Test quality good.
		Continuous Monitors	Test started at 0845 and ended at 1915. Test quality good. Hydrocarbon data fair.
3/20	18	Inlet-North	Test started at 0905 and ran for 770 minutes. Filter clogged and was replaced. Test quality good.
		Inlet South	Test started at 0914 and ran for 770 minutes. At 1850 hrs. Battelle trap froze and was thawed with warm water. Leak developed in Teflon heat line - retarded leak rate with Teflon tape but leak was still 0.11 cfm. At 2250 Battelle trap froze up and was replaced. It was later found that the filter had separated from the housing and particulate had gotten down to the Battelle first. Both filter and trap were replaced and points were retraversed. Test quality good to fair.
		Outlet Ports 2 & 3	Test started at 1000 and ran for 560 minutes. Test quality good.
		Outlet Ports 1 & 4	Test started at 0930 and ran for 560 minutes. Test quality good.
		Hi Volume Sampler	Test started at 1117 and ended at 0540 hrs. Test quality good.
		Continuous Monitors	Test started at 1130 and ended at 2030 hrs. Test quality good. Hydrocarbon data fair.
3/22	19	Inlet North	Test started at 0947 and ran for 770 minutes. Test quality is good.
		Inlet South	Test started at 1001 and ran for 770 minutes. Filter clogged and was replaced. Test quality is good.
		Outlet Ports 2 & 3	Test started at 1000 and ran for 560 minutes. Test quality is good.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/22	19	Outlet Ports 1 & 4	Test started at 1030 and ran for 560 minutes. Test quality is good.
		Hi Volume Sampler	Test started at 1422 and ended at 0415 hrs. Test quality is good.
		Continuous Monitors	Test started at 1145 and ended 2115 hrs. CO drift problems. CO taken off line until 1445 hrs. Test quality good. Hydrocarbon data fair.
3/23	20	Inlet North	Test started at 0927 and ran for 990 minutes. Increased time due to lower plant out put.
		Inlet South	Test started at 0935 and ran for 990 minutes. Increased time due to lower plant output. Test quality good.
		Outlet Ports 2 & 3	Test started at 1005 and ran for 640 minutes. Increased time due to lower plant output. Test quality good.
		Outlet Ports 1 & 4	Test started at 1027 and ran for 640 minutes. Increased time due to lower plant output. Impinger 3 backed up into impinger 2 - not saved. Test quality good.
		Hi Volume Sampler	Test started at 1034 and ended at 0350. Test quality good.
		Continuous Monitor	Test started at 1100 and ended at 0800 hrs. Electronic source balancing problem on CO analyzer. Analyzer (CO) taken off line. No outlet data - gas conditioner not in cycle mode. Test quality good for inlet, hydrocarbon data fair.
3/24	21	Blank	Blank test started at 1200 and ran for 60 minutes at temperature. Test quality good.
		Outlet	Test started at 1110 and ran for 192 minutes. Test quality good.
		Hi Volume Sampler	Off line
		Continuous Monitors	Test started at 1030 and ended at 1530 hrs. Outlet only for inorganic sampling. No CO on line. Test quality good hydrocarbon data fair.
			- QA Test to outlet stream. Test quality good.

TABLE 2-1. (Continued)

Date 1980	Test No.	Sampling Locations	Test Comments
3/25	22	Inlet North and South - QA Test	Test started. No solids or liquids taken for QA. QA test only. Test scrubbed, no samples saved because nozzle was in wrong direction and test would not be duplicate.
		Outlet Ports 1, 2, 3 and 4	Test started at 1120 and ran for 192 minutes. Test quality good.
		Continuous Monitors	Test started at 1115 and ended at 2106 hrs. Test quality good. Hydrocarbon data fair.
		Hi Volume Sampler	Test started at 1030 and ended at 2320 hrs. Filter covered with coal dust. Test quality fair.
3/26	23	Inlet North	QA test started at 1510 and ran for 770 minutes. Test quality good.
		Inlet South	QA test started at 1515 and ran for 770 minutes. Test quality good.
		Outlet Ports 1, 2, 3 and 4	Test started at 0922 and ran for 192 minutes. Test quality good.
		Continuous Monitors	Test started at 1100 and ended at 0830 hrs. No outlet data due to failure of gas conditioner to switch to outlet stream. Test quality good. Hydrocarbon data fair.

TABLE 2-2. DAILY DATA SUMMARIES

Date (1980)	Test No.	Sampling Location		Sample Volume SCF	Sample Volume M^3	Moisture %	Molecular Weight	Velocity fps	Gas Flow acfm	Gas Flow dscfm	Stack Temp °F	Gas Composition O_2 %	CO_2 %	CO ppm	THC ppm	Isokinetics %
3-2	1	Inlet	North	204.617	5.80	9.95	29.01	33.65	132673.22	76549.88	334.31	4.48	12.79	18.00	< 2	63 83
			South	252.517	7.43	7.15	29.35	28.09	116016.35	70423.17	311.78	4.48	12.79	18.00	< 2	89.01
		Outlet	1&4	214.098	6.06	6.32	29.30	22.69	141428.62	86285.62	320.93	6.34	11.31	15.00	< 2	86.20
			2&3	243.024	6.88	6.24	29.31	24.79	154523.14	95704.38	309.92	6.34	11.31	15.00	< 2	93 99
3-3	2	Inlet	North[A]	173.544	4.92	8.39	29.34	37.78	149381.62	85761.77	351.65	4.38	13.80		< 2	
			North[B]	126.934	3.60	8.59	29.32	42.94	169792.93	95782.34	373.36	4.33	13.80	12.00	< 2	95.73
			South[C]	212.049	6.01	7.81	29.41	46.61	184280.23	108410.17	234.83	4.33	13.80	12.00	< 2	80 98
			South[D]	101.519	2 88	7.97	29.39	37.16	146887.38	86004.68	369.90	4.33	13.80	11.00	< 2	107.14
		Outlet	1&4	324.358	9.19	7.45	29.31	26.00	162012.17	94569.98	342.38	5.87	12.44	11.00	< 2	96 33
			2&3	307.313	8.70	7.48	29.31	26.10	162637.08	96037.93	336.94	5.87	12.44	11.00	< 2	90 33
3-4	3	Inlet	North	164.208	5.22	7.43	29 56	45.10	173312.05	96684.71	370.46	4.43	14.41	17.00	< 2	95.59
			South	252.780	7.16	9.48	29.30	43.72	172866.82	96380.09	362.55	4.43	14.41	17.00	< 2	92.25
		Outlet	1&4[E]						Test Scrubbed							
			2&3[E]						Test Scrubbed							
3-5	4	Inlet	North	256.975	7.28	8.14	29.49	43.20	170802.85	97049.64	361.09	4.41	14.56	18.00	< 2	91 43
			South	246.727	6.89	9.03	29.38	41.09	162455.25	92751.96	349.23	4.41	14.56	18.00	< 2	104.10
		Outlet	1&4						Test Scrubbed							
			2&3						Test Scrubbed							
3-6	5	Inlet	North	367.648	10.41	8.93	29.28	42.92	169692 43	102970.06	363.83	4.35	13.79	18.00	< 2	97.28
			South	323.174	9.15	9.72	29.18	43.48	171937.31	97295.97	347.46	4.35	13.79	18.00	< 2	90.54
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-7	6	Inlet	North	368.684	10.44	18.32	28.14	43.61	172425.59	87432.05	351.00	4.59	13.92	16.00	< 2	105 93
			South	365.424	10.35	9.18	29.27	44.01	173994.36	99965.91	335.86	4.59	13.92	16.00	< 2	99.65
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-8	7	Inlet	North	351.419	9.95	9.56	29.19	39.62	156673.06	85266.27	377.55	4.79	13.60	28.00	< 2	103.54
			South	333.613	9.45	9.75	29.16	39.28	155327.60	86179.64	359.83	4.79	13.60	28.00	< 2	105.53
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-9	8	Inlet	North[F]	74.033	2.10	7.79	29.19	30.27	119098 00	71325.76	316.83	7.1	11.6	25.00	< 2	95.60
			North[G]	294.807	8.35	8.05	29.16	30.38	120108.29	67223.13	364.73	7.1	11.6	25.00	< 2	98.51
			South[H]	121.924	3.45	7 78	29.20	36.43	144173.75	82977.48	344.38	7.1	11.6	25.00	< 2	106.23
			South[I]	140.223	3 97	8.02	29.17	27.38	108274.04	64436.72	315.88	7.1	11.6	26.00	< 2	60.56[J]
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-10	9	Inlet	North	130.811	3.70	8.59	29.31	45.23	178853.20	103205.95	362.09	3.7	13 9	25.00	< 2	88 84
			South	193.613	5.48	17.13	28.25	43.77	173045.12	92980.29	330.65	3.7	13.9	25.00	< 2	89.58
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-11	10	Inlet	North	394.094	11.16	6.98	29.49	45.68	180619 64	101867.66	374.75	4.7	13.5	22.00	< 2	97.17
			South	363.006	10.85	8.48	29.30	44.20	174783.47	99143.40	356.59	4.7	13.5	22.00	< 2	105.29
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-12	11	Inlet	North[E]						Test Scrubbed							
			South						Test Scrubbed							
		Outlet	1&4						Not Tested							
			2&3						Not Tested							
3-13	12	Inlet	North	350.455	9.92	8.63	29.53	42.45	160079.96	93473.48	361.78	3.34	15.56	21.00	< 2	102.35
			South	369 824	10.47	8.54	29.54	41.41	164036 17	93628.05	340.61	3.34	15.56	21.00	< 2	102.23
		Outlet	1&4[K]	158.981	4.50	7.10	29.56	25.85	161102.30	95146.81	339.44	5.17	13.97	18 00	< 2	77 72
			2&3	365 290	10.35	9.37	29.28	26 58	165622.22	98426.04	315.08	5.17	13.97	18 00	< 2	91.73

TABLE 2-2. (Continued)

Date (1980)	Test No.	Sampling Location		Sample Volume SCF	Sample Volume M^3	Moisture %	Molecular Weight	Velocity fps	Gas Flow acfm	Gas Flow dscfm	Stack Temp °F	Gas Composition O^2 %	Gas Composition CO_2 %	Gas Composition CO ppm	Gas Composition THC ppm	Isokinetics %
3-14	13	Inlet	North	374.335	10.60	9.67	29.31	43.48	171904.78	94404.58	384.68	3.70	14.81	28.00	< 2	101.27
			South	352.110	9.97	9.70	29.30	41.49	164048.73	91011.47	375.70	3.70	14.81	28.00	< 2	107.20
		Outlet	1&4	367.772	10.42	9.80	29.14	24.34	151720.16	83869.92	365.94	5.31	13.18	30.00	< 2	99.80
			2&3	351.364	9.95	9.50	29.15	24.84	154819.20	86429.81	358.75	5.31	13.18	30.00	< 2	96.74
3-15	14	Inlet	North	276.767	7.83	8.14	29.27	30.86	121976.44	68088.12	368.23	6.31	12.59	22.00	< 2	102.11
			South	268.37	7.60	7.68	28.32	29.96	118444.95	67307.85	357.65	6.31	12.59	22.00	< 2	108.67
		Outlet	1&4	319.13	9.04	7.88	29.09	20.00	124662.69	75394.82	319.42	8.37	10.67	19.00	< 2	104.05
			2&3	307.00	8.69	7.83	29.10	21.31	132801.77	76705.48	356.65	8.37	10.67	19.00	< 2	96.83
3-17	15	Inlet	North	359.800	10.19	8.83	29.36	41.89	165622.66	91774.43	371.23	3.73	14.40	22.00	< 2	106.85
			South	390.474	11.06	8.17	29.44	42.84	169381.86	97210.69	348.41	3.73	14.40	22.00	< 2	99.99
		Outlet	1&4	406.855	11.52	8.71	29.21	26.01	162117.20	93334.49	354.56	5.43	12.90	22.00	< 2	107.18
			2&3	391.836	11.10	8.43	29.25	27.27	169966.05	98183.52	345.31	5.43	12.90	22.00	< 2	95.48
3-18	16	Inlet	North	369.159	10.45	9.36	29.29	43.06	170259.70	92573.11	381.96	3.82	14.39	23.00	< 2	100.17
			South	371.497	10.52	8.73	29.37	41.89	165639.94	93891.77	354.96	3.82	14.39	23.00	< 2	108.07
		Outlet	1&4	392.696	11.12	8.62	29.24	27.12	169022.81	96719.62	360.06	5.42	13.00	24.00	< 2	99.82
			2&3	353.252	10.00	9.09	29.18	25.60	159531.72	91103.75	367.50	5.42	13.00	24.00	< 2	93.81
3-19	17	Inlet	North	349.709	9.90	9.68	29.29	41.87	165560.57	88914.41	360.28	3.60	14.40	24.00	< 2	107.21
			South	368.751	10.44	8.68	29.37	43.42	171695.37	95341.29	361.59	3.60	14.40	24.00	< 2	97.16
		Outlet	1&4	374.299	10.60	10.28	29.03	26.75	166699.92	91080.57	373.12	5.30	13.00	26.00	< 2	101.03
			2&3	360.578	10.21	8.59	29.24	26.92	167762.85	94194.67	365.94	5.30	13.00	26.00	< 2	92.62
3-20	18	Inlet	North	347.892	9.85	8.31	29.33	42.13	166670.31	94786.10	350.98	3.80	13.80	22.00	< 2	92.21
			South	368.079	10.42	7.86	29.39	42.11	166487.56	96189.05	342.65	3.80	13.80	22.00	< 2	104.31
		Outlet	1&4	356.204	10.09	7.79	29.29	24.63	153481.74	90622.79	338.12	6.00	12.50	17.00	< 2	95.09
			2&3	388.522	11.00	8.44	29.21	26.91	167725.85	97760.61	342.81	6.00	12.50	17.00	< 2	97.71
3-22	19	Inlet	North	363.462	10.29	8.54	29.36	41.65	164688.40	94207.94	348.64	3.60	14.20	38.00	< 2	105.17
			South	348.597	9.87	8.07	29.41	39.63	156677.09	90821.39	342.09	3.60	14.20	38.00	< 2	96.42
		Outlet	1&4	402.144	11.39	8.61	29.19	26.26	163656.04	95997.17	340.00	5.30	12.70	38.00	< 2	104.10
			2&3	401.160	11.36	8.23	29.24	26.81	167077.26	99549.08	330.60	5.30	12.70	38.00	< 2	99.03
3-23	20	Inlet	North	336.525	9.53	8.16	29.26	28.65	113282.76	63470.17	364.41	6.00	12.60	L	< 2	103.54
			South	330.733	9.37	12.74	28.69	27.26	107773.49	58005.38	355.41	6.00	12.60		< 2	115.99
		Outlet	1&4	301.612	8.54	9.73	28.82	16.63	103629.07	58763.10	354.13	9.70	10.00		< 2	110.46
			2&3	358.078	10.17	5.87	29.28	19.70	122765.69	74046.56	338.13	9.70	10.00		< 2	102.66
3-24	21	Inlet	North						Blank Run							
			South						Blank Run							
		Outlet	1,2,3&4	130.420	3.69	9.53	29.16	25.78	100547.70	90172.96	365.47	5.4	13.2		< 2	103.72
3-25	22	Inlet	North[E]						Test Scrubbed							
			South[E]													
		Outlet	1,2,3&4	122.788	3.48	9.92	29.10	24.58	153166.31	87025.45	356.40	5.4	13.2		< 2	101.06
3-26	23	Inlet	North	326.820	9.26	9.17	29.13	37.23	147200.78	81800.81	380.80	6.00	12.60		< 2	106.24
			South	344.976	9.77	9.09	29.14	37.40	147872.05	80733.46	382.45	6.00	12.60		< 2	118.43
		Outlet	1,2,3&4	138.673	3.93	9.26	29.24	26.42	164679.85	93244.39	364.38	4.80	13.70		< 2	106.64

A With .312 nozzle
B With .250 nozzle changed to maintain flow
C With .312 nozzle
D With .237 nozzle changed to maintain flow
E No sample retained
F With .250 nozzle
G With .310 nozzle changed to maintain flow
H With .240 nozzle
I With .309 nozzle changed to maintain flow
J Results questionable due to bad leak rate
K Test cancelled due to cold weather. Sample saved
L Monitor not working

TABLE 2-3. 24 HOUR PROCESS DATA FOR THE AMES MUNICIPAL POWER PLANT, UNIT NO. 7

Date	3-2-80		3-3-80		3-4-80		3-5-80		3-6-80		3-7-80		3-8-80		3-9-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
MW Gross	30.19*	2.8*	30.1	7.31	31.58	5.19	31.9	4.76	31.7	5.55	30.5	7.51	27.85	6.01	20.9	5.31
MW Net	26.25*	1.51*	32.04*	0.98*	29.25	4.93	29.72	4.44	28.88	5.30	28.24	7.21	25.66	5.79	18.9	5.12
Steam flow rate (1000's lbs/hr)	252.2	36.49	268.8	71.48	284.87	56.59	289.58	48.47	279.79	56.73	274.8	74.9	239.33	61.67	178	46.7
Steam pressure (psig)	857.7	4.16	852.71	4.66	850.63	5.95	848.54	5.61	847.33	7.22	850.21	5.21	851.04	6.08	854	12.3
Steam temperature (^oF)	899.63	8.53	890.1	24.01	891.46	14.63	895.6	10.97	895.33	9.89	891.8	15.19	893	12.93	888	15.5
Feedwater flow rate (1000's lbs/hr)	261.17	37.94	278.38	71.65	290.79	52.98	300.42	46.6	291.7	54.23	286.33	76.82	251.4	62.96	181	59.3
Feedwater temperature (^oF)	366*	7.38*	380.81	2.14	389.7	7.63	382.8	17.36	377.5	21.03	378.75	26.6	360.2	25.81	338	24.0
Fuel feed rate (1000's lbs/hr) 1	31.7	7.07	31.93	7.32	31.03	5.37	32.45	6.09	35.38	1.53	31.65	8.23	32.03*	1.17*	24.8	5.75
Fuel feed rate (1000's lbs/hr) 2	32.2		31.69		31.81		33.53		32.15		33.6		28.17		23.7	
Fuel oil (gallons/hr)	4.6		4.6		2.9		2.5		3.75		4.2		5.4		6.25	
Excess air %	22	2.1	22.08	8.28	20.33	2.35	20.17	3.92	22.21	6.3	25.25	11.2	25.48	10.9	34	12.6
ID fans amps	46.42	1.1	45.75	2.15	46.04	1.76	46.75	1.11	46.2	1.6	46.46	2.41	45	1.72	44	1.6
ID fans pressure (psig)	5.15	0.89	5.67	1.40	6.17	1.14	6.09	1.04	6.08	0.89	6.06	1.4	5.21	1.07	4.2	0.76
FD fans amps	30.29	1.12	29.91	1.79	29.54	1.41	30.46	1.35	30.3	1.5	30.67	1.79	29.44	0.97	28	1.5
FD fans pressure (psig)	4.26	0.77	3.94	1.13	4.32	0.78	4.32	1.06	4.5	1.3	4.54	1.41	3.54	1.03	3.1	1.05
Furnace draft (psig)	0.60	0.20	0.59	0.18	0.59	0.15	0.62	0.15	0.6	0.13	0.63	0.12	0.53	0.10	0.59	0.092
Flue gas temp (^oF) Boiler exit	647*	9.78*	688*	17.51*	687*	9.19*	695*	6.67*	688*	6.3*	699*	3.94*	662*	10.33*	629*	20.2*
Flue gas temp (^oF) ESP inlet	318.5*	6.69*			341*	3.16*	345.5*	1.58*	340*	0*	342*	4.22*	327*	8.23*	305*	21.2*
Ambient temperature (^oF)	16.06	7.58	27.39*	10.39*	24.08	6.81	7.63	5.22	19.79	9.19	24.58	4.29	28.17	4.99	37	7.5
Ambient pressure inches Hg	29.34	0.18	28.89*	0.11*	28.88*	0.06*	29.17	0.08	29.04	0.1	28.97	0.048	29.01	0.06	28.89	0.097

(Continued)

* Not based on 24 hour readings

1 Based on tachometer type gauge

2 Based on weight type gauge

TABLE 2-3. (Continued)

Date	3-10-80		3-11-80		3-12-80		3-13-80		3-14-80		3-15-80		3-17-80		3-18-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
MW Gross	29.1	8.77	30.8	6.10	31.2	6.26	31.2	6.11	30.5	6.25	21.7	5.95	29.5	7.74	31.8	3.84
MW Net	26.7	8.43	28.0	6.20	27.1	7.99	28.3	6.16	28.0	6.01	19.6	5.68	27.2	7.58	29.3	3.65
Steam flow rate (1000's lbs/hr)	254	80.2	277	62.8	255	94.0	268	82.2	270	62.8	186	55.06	259	76.1	283	40.0
Steam pressure (psig)	853	9.1	855	6.24	855	5.8	853	8.6	852	7.0	850	8.6	850	5.3	850	6.3
Steam temperature (^{o}F)	892	11.5	894	11.2	893	11.0	893	12.2	894	12.5	888	11.1	892	9.4	890	16.2
Feedwater flow rate (1000's lbs/hr)	266	83.1	277	78.5	279	80.2	286	71.0	281	61.3	194	54.0	268	74.5	295	38.1
Feedwater temperature (^{o}F)	362	34.9	372	23.6	370	25.2	371	23.4	371	21.8	330	69.4	367	26.3	375	11.7
Fuel feed rate 1 (1000's lbs/hr)	28.8	9.03	29.1	7.08	30.5	7.13	31.9	9.81	30.4	6.64	24.2	6.6	30.9	7.23	32.0	3.84
Fuel feed rate 2	31.2		30.3		31.0		33.4		30.7		24.0		31.2		31.6	
Fuel oil (gallons/hr)	4.17		11.25		12.08		2.08		3.75		37.9		2.92		2.50	
Excess air %	24	12.9	20	5.1	20	5.9	23	9.8	24	11.3	39	12.5	26	13.3	21	3.6
ID fans amps	45	2.5	46	3.1	46	1.8	46	1.5	45	1.5	42	4.0	46	1.6	46	0.98
ID fans pressure (psig)	5.4	1.32	6.0	1.18	6.2	1.20	6.0	0.91	5.9	1.01	4.3	0.81	5.0	1.00	5.8	0.77
FD fans amps	30	1.3	30	1.1	28	6.2	30	1.5	29	1.5	28	1.4	30	1.6	30	1.0
FD fans pressure (psig)	4.0	1.18	4.6	1.12	4.4	1.46	4.2	1.20	3.7	1.12	3.0	1.00	4.1	1.09	4.1	0.97
Furnace draft (psig)	0.60	0.036	0.58	0.024	0.61	0.042	0.63	0.024	0.62	0.044	0.74	0.092	0.59	0.074	0.59	0.1
Flue gas temp (^{o}F) Boiler exit	685*	5.3*	664*	37.3*	675*	31.1*	686*	37.5*	669*	30.2*	625*	27.3*	669*	48.9*	676*	24.0*
ESP inlet	340*	0*	323*	27.1*	327*	14.6*	324*	20.1*	326*	16.0*	295*	20.2*	319*	21.3*	326*	9.5*
Ambient temperature (^{o}F)	27	7.5	25	7.9	30	1.6	28	2.6	37	12.6	51	11.2	34	4.9	49	12.8
Ambient pressure inches Hg	28.91	0.195	29.14	0.061	28.88	0.08	28.89	0.13	29.11	0.02	28.98	0.10	29.09	0.04	29.06	0.07

(Continued)

TABLE 2-3. (Continued)

Date	3-19-80		3-20-80		3-22-80		3-23-80		3-24-80		3-25-80		3-26-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
MW Gross	31.0	5.01	30.6	5.88	29.4	5.16	18.1	1.98	29.7	7.77	29.5	7.54	30.5*	6.17*
MW Net	27.2	6.96	26.8	7.68	27.1	4.95	16.2	1.80	27.4	7.55	27.2	7.21	27.7*	6.29*
Steam flow rate (1000's lbs/hr)	277	52.1	273	59.8	260	61.3	153	16.2	264	73.5	262	71.9	258	79.1
Steam pressure (psig)	853	7.0	851	5.0	853	7.4	852	5.7	858	4.9	852	4.8	854	4.4
Steam temperature (^{o}F)	888	12.1	891	12.3	891	11.8	884	10.0	891	11.2	892	10.7	890	16.6
Feedwater flow rate (1000's lbs/hr)	287	50.6	222	115.4	270	50.5	162	17.8	273	72.5	272	71.4	283	61.6
Feedwater temperature (°F)	375	16.5	372	16.8	365	18.9	325	7.1	367	25.4	364	27.6	369	20.9
Fuel feed rate 1 (1000's lbs/hr)	31.1	5.74	33.6	7.06	31.3	8.32	20.8	1.71	32.3	8.26	31.8	7.66	29.6	7.16
Fuel feed rate 2 (1000's lbs/hr)	31.4		34.4		31.1		20.4		32.8		31.8		31.9	
Fuel oil (gallons/hr)	4.17		20.4		26.67		33.33		20.4		28.33		1.67	
Excess air %	20	5.9	27	7.7	22	3.8	42	11.0	25	10.8	27	14.3	22	4.8
ID fans amps	45	1.3	46	1.8	45	1.7	42	0.7	46	2.2	46	1.6	45	1.3
ID fans pressure (psig)	5.7	0.85	5.9	0.9	5.3	0.9	3.8	0.22	6.1*	0.27*	5.7	1.14	5.6	1.24
FD fans amps	29	1.5	29	6.4	29	1.5	27	0.6	29	1.7	30	1.3	29	1.5
FD fans pressure (psig)	3.9	1.18	4.8	1.32	4.1	0.99	2.3	0.3	4.1	0.92	4.2	0.84	3.9	1.37
Furnace draft (psig)	0.6	0.10	0.6	0.09	0.59	0.1	0.59	0.057	0.53	0.07	0.57*	0.11*	0.53	0.09
Flue gas temp (^{o}F) Boiler exit	666*	30.2*	681*	32.8*	659*	30.4*	599*	3.9*	660*	36.1*	670*	31.6*	664	37.1
Flue gas temp (^{o}F) ESP inlet	328*	15.9*	324*	12.7*	320*	12.2*	280*	0*	322*	23.1*	323*	2.03*	315	16.6
Ambient temperature (°F)	56	9.3	44	9.2	04	5.9	37	1.6	36	1.0	38	6.3	40	4.1
Ambient pressure inches Hg	28.81	0.09	28.92	0.085	29.04	0.134	28.97	0.04	29.04	0.08	29.17	0.024	29.17	0.05

TABLE 2-4. TEST DURATION PROCESS DATA FOR THE AMES MUNICPAL POWER PLANT, UNIT NO. 7

Date	3-2-80		3-3-80		3-4-80		3-5-80		3-6-80		3-7-80		3-8-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
Duration of Test	1100 to 2100		0900 to 2000		0900 to 1900		0900 to 1900		0800 to 2300		0800 to 2300		0800 to 2300	
MW Gross	31	2.31	34.8	0.3	35.2	0.3	35.0	0.2	34.6	0.8	35.3	1.0	31.3	2.2
Net	NS	NS	32.3	0.3	32.7	0.2	32.6	0.2	32.2	0.8	32.8	1.0	29	2.1
Steam flow rate 1000's lbs/hr	278.2	21.5	315.9	5.2	324	3.0	319.1	3.8	315.4	10.3	322.8	11.9	275.6	23.7
Steam pressure psig	859.5	3.5	852.1	4.0	850.5	3.5	850.5	3.5	848.8	6.2	852.2	4.5	851.9	7.3
Steam temperature ^{o}F	903.6	6.4	902.5	6.2	900.5	3.5	902.3	6.8	897.8	10.2	895.1	12.1	895.3	12.2
Feedwater flow rate 1000's lbs/hr	287.5	24.6	321.8	5.8	325.5	9.1	328.1	6.0	325.4	11.7	336.5	13.6	288.5	24.1
Feedwater temperature ^{o}F	NS	NS	381.3	2.3	390.5	6.1	394.1	3.0	388.8	3.4	390.1	6.9	375	7.3
Fuel feed rate (coal)	34.9	2.6	36.2	2.1	34.3	0.8	35.5	3.0	35.4	1.5	35.7	5.5	32.1	1.1
Fuel oil gallons/hr														
Excess air %	22.1	1.6	18.3	4.7	20.1	1.8	18.7	1.3	18.9	1.4	19.3	1.1	19.5	1.0
ID fans amps	47.3	0.5	46.9	0.8	47.2	0.4	47.2	0.4	47.1	0.6	47.9	0.9	46	0.8
ID fans pressure psig	5.6	0.8	6.6	0.4	7.0	0.2	6.7	0.2	6.5	0.6	6.9	0.3	5.84	0.5
FD fans amps	30.8	1.2	30.8	0.8	30.4	0.5	30.9	0.7	31.2	0.8	31.8	0.6	30.0	0.3
FD fans pressure psig	4.6	0.8	4.5	0.7	4.7	0.3	4.4	0.6	5.2	0.8	5.3	0.7	4.1	0.7
Furnace draft psig	0.7	0.1	0.6	0.1	0.6	0.07	0.62	0.11	0.57	0.1	0.65	0.07	0.5	0.07
Flue gas temp (^{o}F)														
Boiler exit	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS
ESP inlet	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS	NS
Ambient temperature ^{o}F	23	3.1	NS	NS	24.2	3.6	10.9	4.1	25.3	5.4	26.9	3.2	30.1	4.9
Ambient pressure inches Hg	29.22	0.09	NS	NS	28.85	0.03	29.23	0.01	28.98	0.05	28.94	0.04	29.05	0.02

(Continued)

NS - Not Sufficient Data

TABLE 2-4. (Continued)

Sampling Day	3-9-80		3-10-80		3-11-80		3-12-80		3-13-80		3-14-80		3-15-80		3-17-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
MW Gross	21.0	5.14	35.0	0	35.0	0	35.5	0.58	35.0	0	34.4	1.12	19.6	6.59	34.8	0.24
Net	19.1	4.94	32.3	0.04	32.4	0.09	32.8	0.61	32.4	0.10	31.8	1.11	18.2	6.56	32.4	0.62
Steam flow rate	177	46.6	310	5.0	320	5.5	325	0	320	0	309	14.5	182	66.8	312	3.8
Steam pressure	849	2.3	858	5.6	857	4.7	855	0	855	3.2	855	5.7	851	3.7	853	3.8
Steam temperature	892	12.2	896	11.9	898	8.6	905	5.8	899	5.1	896	12.3	889	12.5	895	8.4
Feedwater flow	188	47.8	323	3.5	330	3.2	332	5.0	330	0	319	13.8	184	64.2	321	4.8
Feedwater temperature	340	21.9	390	0	388	2.6	390	0	385	1.4	384	3.1	336	24.9	383	2.5
Fuel feed rate (coal) 1000's lbs/hr	25.2	6.04	36.3	2.27	33.8	1.18	35.1	0.25	38.6	2.82	34.4	2.03	23.0	7.34	35.1	1.71
Fuel oil gallons/hr	6.25†	NA	4.17†	NA	11.25†	NA	12.08†	NA	2.08†	NA	3.75†	NA	37.92†	NA	2.92†	NA
Excess air	34	12.1	16	0.8	18	1.0	18	2.9	18	1.1	17	1.5	41	14.1	18	1.6
ID fans amps	44	1.9	47	0.9	47	0.7	48	0.6	47	0.5	46	0.8	41	4.8	46	0.6
ID fans pressure	4.2	0.81	6.2	0.25	6.8	0.29	7.4	0.48	6.4	0.30	6.4	0.50	4.0	0.80	5.5	0.82
FD fan amps	28	1.8	30	0	30	0.5	30	0	31	0.51	30	0.7	28	1.5	30	0.51
FD fan pressure	2.9	1.01	4.8	0.36	5.3	0.45	6.0	0.71	4.9	0.71	4.2	0.86	2.7	1.00	4.7	0.60
Furnace draft	0.59	0.078	0.61	0.033	0.58	0.024	0.60	0.071	0.63	0.015	0.62	0.047	0.70	0.035	0.58	0.071
Boiler flue gas temp	632*	18.6*	686	5.3	688*	13.7*	690	11.6	709	11.1	685	15.0	618	30.4	695*	35.6*
ESP inlet temperature	309*	16.9*	340	0	340*	0*	335	0	335	1.4	334	1.8	289	21.3	331*	2.2*
Ambient temperature	42	4.4	22	1.6	31	4.0	30	0.5	30	1.5	46	5.8	10	4.2	37	4.7
Ambient pressure	28.82	0.023	28.96	0.091	29.11	0.053	28.85	0.022	28.92	0.123	29.11	0.018	28.92	0.048	29.12	0.030
Sampling duration	8:30A-10:11P		8:10A-5:33P		8:25A-10:35P		9:10A-1:15P		8:35A-9:47P		8:40A-10:55P		9:05A-10:06P		8:49A-10:25P	

(Continued)

TABLE 2-4. (Continued)

Sampling Day		3-18-80		3-19-80		3-20-80		3-22-80		3-23-80		3-24-80		3-25-80		3-26-80	
		Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
MW	Gross	34.0	1.90	33.0	4.30	31.8	5.45	29.4	6.93	18.5	1.51	34.8	0.29	34.6	0.48	35.0	0.6
	Net	31.4	1.91	30.4	4.15	28.8	5.42	26.9	6.66	16.6	1.36	32.7	0.76	32.2	0.57	32.5	0.6
Steam flow rate		307	19.5	297	44.1	281	57.6	260	66.3	155	11.9	311	2.5	311	3.0	310	0.9
Steam pressure		851	6.0	852	6.8	853	3.8	851	7.5	856	4.8	855	5.8	851	4.8	852	2.7
Steam temperature		894	11.1	888	13.9	892	12.5	889	13.6	886	7.7	899	11.8	892	9.6	902	14.8
Feedwater flow		318	20.5	307	44.1	292	55.8	270	66.2	156	38.2	321	4.8	324	2.4	327	3.9
Feedwater temperature		383	4.2	382	12.7	372	19.8	365	25.7	328	7.9	384	2.5	384	2.5	380	0
Fuel feed rate						33.3	8.20	33.2	7.92	21.4	1.28	33.1	1.03	33.8	0.50	35.1	2.84
Coal (1000's lbs/hr)		33.5	2.26	32.6	6.16												
Fuel oil gallons/hr																	
Excess air		20	1.8	19	6.0	24	3.4	26	13.0	38	10.6	16	1.7	18	1.0	18	0.6
ID fans amps		46	0.5	45	0.9	46	2.4	45	1.3	42	0.6	48	1.0	48	0	46	0
ID fans pressure		6.2	0.46	4.5	0.99	5.8	1.09	5.4	1.02	3.8*	0.24*	6.2	0.17	4.8	1.82	6.6	0.34
FD fan amps		30	0.4	30	1.5	30	1.9	30	1.6	27	0.4	30	0	30	0	30	0
FD fan pressure		4.4	0.61	4.4	1.01	6.5	6.60	4.1	1.14	2.3	0.36	4.5	0.10	4.8	0.51	4.7	0.80
Furnace draft		0.60	0.107	0.60	0.109	0.81	1.019	0.61	0.056	0.58	0.057	0.52	0.093	0.59	0.075	0.53	0.065
Boiler flue gas temp		687*	7.8*	686*	8.6*	695*	15.9*	679*	9.8*	598*	4.6*	674	11.1	676	11.1	689	16.0
ESP inlet temperature		330*	3.6*	338*	2.5*	330*	4.8*	328*	2.6*	280*	0*	335	0	335	0	325	3.5
Ambient temperature		58	6.8	62	6.3	42	6.2	42	4.2	37	1.5	37	1.5	44	0.8	43	2.6
Ambient pressure		29.02	0.056	28.75	0.042	29.03	0.106	28.95	0.078	28.98	0.024	29.05	0.012	29.16	0.018	29.17	0.041
Sampling duration		9:00A-11:25P		8:43A-12:07A		9:05A-4:25A		9:47A-2:12A		9:27A-2:10A		11:10A-3:47P		11:20A-3:46P		9:22A-2:06P	

* Not a total time mean.

Unit No. 7 generally operated between a range of 16 to 35 MW gross, (refer to daily process data tables provided in Appendix D). Production over 35 MW placed considerable wear on the unit, and was avoided whenever possible. Production under 16 MW introduced instability and the possibility of large transient swings in operating conditions. Usually the boiler was operating close to one of these limits. It operated at 35 MW during peak-loads because the load of the serviced community was over 35 MW. Production was reduced to 16 MW when off-peak power could be bought more cheaply from neighboring utilities.

Examination of Table 2-3 indicates that the daily mean of gross electrical output (24 hour basis) is typically between 29 and 32 MW due to boiler operation at full output for a large portion of the day. In fact, the hourly readings provided in Appendix D indicate that output is rarely below 35 MW between the hours of 8 AM and 10 PM or longer. During non-peak hours, the boiler operated between 16 and 25 MW, depending on load and the amount of power being purchased from neighboring utilities. Comparison of the daily cycles of power production with the standard deviations (24 hour basis) given in Table 2-3, indicates that the standard deviations range between 5 and 7 for days representative of typical operation. Values not lying in this range are indicative of abnormalities such as the buying of cheaper power through the peak hours, or unusually high off-peak loads. The standard deviations in Table 2-3 show that these abnormalities happen most often on weekends, especially Sundays. Weekday operation is fairly consistent, due to uniformly high loads and the resultant high cost of power. Net power output follows identical trends, since the power demand of the auxiliary equipment associated with Unit No. 7 is fairly constant.

Fuel consumption varied directly with the amount of electricity produced. Of the three types of fuels used in Unit No. 7 (coal, RDF, and fuel oil), coal was used in the largest quantities. The amount of RDF burned was limited to approximately 17% in terms of the total heat produced. This was because RDF, due to its lower heating value, cannot sustain sufficient temperatures to maintain required boiler efficiency and steam quality. Also, RDF requires a longer residence time in the boiler for complete combustion, and this places another physical restriction on the amount of RDF in the fuel mixture. Fuel oil is used sparingly, and only as an igniter to insure flame continuity during soot blowing. Different firemen have different procedures for its use, and the large variations in fuel oil consumption shown in Table 2-3 are more related to operating practices than to what was happening in the boiler.

The continuous supply of RDF to the boiler during the test was found to be unreliable. Practical experience during the test indicated that RDF supply was very unreliable. The RDF conveyors which feed Unit No. 7 were prone to jamming and required frequent maintenance. Often the RDF supply ran out because the solid waste recovery plant was experiencing mechanical problems, or had run out of refuse to process. Out of 23 days of sampling, only on 6 was RDF burned continuously. On 15 days RDF was burned part of the time, and on 2 days it was not burned at all (refer to Appendix D).

The means and standard deviations for coal consumption given in Table 2-3 follow those of the gross electrical output. This indicates that coal consumption is closely related to electrical output, as expected. However, these daily averages mask out one important effect. Referring to the tables in Appendix D, one can see that the amount of coal burned depends on whether there is RDF in the mixture or not. All other things being equal, the flow of coal will always go up or down, depending on whether RDF is being removed or introduced into the mixture, respectively.

2.2.1 Operating Parameters

Data for the steam cycle in the boiler are also listed in Table 2-3. Examination of the data indicates that the steam and feedwater flow rates fluctuate in a daily cycle, with means and standard deviations following the gross electrical output. However, the values for steam temperature and pressure remain fairly constant. The feedwater temperature also varied. It was higher on days of high electricity production, and lower on days of low production.

Excess air is one of the most important parameters for describing conditions inside the combustion chamber. Unit No. 7 is designed to operate at about 20% excess air. Data in Table 2-3 indicates that on the average this is true. However, the hourly data (refer to Appendix D) indicates wide fluctuations. Excess air tended to increase as the boiler load decreased.

This was possibly due to the operater not decreasing the intake air with the reduction in fuel supply. On nearly each night the excess air reading was greater than 50% (the maximum readable value on the meter). The standard deviations of the mean excess air values indicate no direct relationshop to the deviations of gross power output. Consequently, excess air is not a function of power output alone. Unlike most other parameters, the excess air setting was subject to the whim of the operator, and changes from work shift to work shift could have introduced important variations.

The induced and forced draft fan measurements listed in Table 2-3 are of limited significance , since they did not respond to increases in production with greater airflows and correspondingly greater current consumption. The furnace draft data indicated little or no correspondence to any of the other measured data. Most of the flue gas and ESP inlet temperature readings were incomplete as they did not cover the entire 24 hour day. Most of this information was recorded during peak operation, and may therefore be considered representative for peak operation conditions. Both the flue gas and ESP inlet temperatures decreased during off-peak periods.

Routine activities such as ash removal and soot blowing was performed at times designated in the test plan. RDF was observed to have a substantially higher ash content than coal, and this characteristic was reflected by longer ash removal periods, and more periodic soot blowing. Both activities decreased substantially when RDF was not being burned.

2.2.2 Test Duration Data

Table 2-4 contains means and standard deviations for all of the parameters given in Table 2-3 on a test duration basis. They are derived from the same hourly data given in Appendix D, but the averages are taken over shorter periods of time than the 24 hour means discussed previously. These values are included only to indicate what operating conditions existed during the hours of each test. They are not, however, indicative of overall boiler performance. For instance, some tests were performed only over peak hours. These means would be indicative only of peak conditions, and the corresponding standard deviations would be very small, since the parameters remained fairly constant during this period.

2.2.3 Daily Production and Consumption Data

Table 2-5 contains information recorded by the power plant on a daily basis. The total gross and net power production was recorded directly from meters inside the plant. The total steam produced divided by the gross power production gave a good indication of boiler efficiency. Separate meters are used for measuring the water used for ash removal and the total input to the evaporators. The days of highest sluice water use corresponded with days of prolonged use of RDF in the fuel mixture. The evaporators eventually feed into the working fluid cycle of the boiler, and gave a fair indication of make-up water required, except that there was a water reclamation system attached to the boiler. Hence, these values indicated new input to the system, but did not account for total make-up water requirements.

Most of the fuel types were very accurately measured. Coal was measured through a weight integrating system, and fuel oil was similarly measured through a volume integrating system. However, no accurate measurement of the RDF was possible. The values listed were derived from volumetric readings and a very rough measurement of the RDF density, taken once every shift. The Btu contribution of each fuel was then calculated by doing calorimetric analyses. This was done periodically, and the values used for the duration this test program are given in Table 2-6. By summing the Btu contribution of each fuel, a value for total heat production can be found. This value was then divided by either the gross or net electricity production to express thermal energy as it related to the power production of the day.

2.3 Continuous Monitoring Data

Table 2-7 presents the daily averages of O_2, CO_2, CO, and total hydrocarbon monitoring on approximate test duration basis. Occasionally the continuous monitors were allowed to run longer than the actual test, but the data can still be considered to be representative of the test duration. Hydrocarbon values were always found to be lower than 2 ppm, the sensitivity limit of the instrumentation used.

TABLE 2-5. DAILY PRODUCTION AND CONSUMPTION AT AMES MUNCIPAL POWER PLANT, UNIT NO. 7

Date	Power Production (kwh) Gross	Power Production (kwh) Net	Thermal Energy† (Btu/kwh) Gross	Thermal Energy† (Btu/kwh) Net	Steam Production (lb/kwh)	Fuel Consumption: Iowa Coal (lbs)	Fuel Consumption: Colorado Coal (lbs)	Fuel Consumption: RDF* (lbs)	Fuel Consumption: Oil (gallons)	Sluice Water for Bottom and Fly Ash Removal (gallons)	Water Input to Evaporator (gallons)
3-2-80	681 000	623 902	11 186	12 210	9.57	339 988	432 712	0	60	250 000	8 300
3-3-80	709 000	648 682	11 296	12 346	9.59	418 330	342 270	113 000	160	340 000	9 000
3-4-80	761 000	700 072	11 396	12 388	9.53	412 290	351 210	226 800	70	320 000	2 200
3-5-80	759 000	698 461	11 697	12 711	9.73	434 538	370 162	192 375	60	380 000	6 800
3-6-80	740 000	679 858	11 693	12 728	9.50	432 096	339 504	213 200	90	450 000	9 200
3-7-80	735 000	674 470	11 652	12 697	9.64	427 127	378 773	130 800	100	320 000	2 500
3-8-80	648 000	590 057	11 602	12 742	9.54	358 286	317 720	168 460	130	360 000	1 120
3-9-80	494 000	443 496	11 524	12 836	9.47	301 888	267 712	26 000	150	314 908	8 500
3-10-80	693 000	635 037	10 955	11 985	9.54	486 980	262 220	81 200	100	386 716	6 300
3-11-80	739 000	678 629	11 440	12 458	9.57	334 328	392 472	229 600	270	403 172	5 800
3-12-80	750 000	688 456	11 348	12 362	9.62	408 980	334 620	229 075	290	413 644	3 500
3-13-80	742 000	681 889	11 544	12 562	9.68	432 270	368 230	144 075	50	422 620	9 100
3-14-80	729 000	668 119	11 537	12 588	9.51	412 440	324 060	230 400	90	418 132	0
3-15-80	508 000	457 939	11 434	12 684	9.50	322 448	253 352	22 050	910	335 104	5 700
3-17-80	699 000	639 942	11 170	12 201	9.59	412 335	337 365	97 650	70	396 000	11 100
3-18-80	759 000	696 494	10 855	11 829	9.52	417 010	341 190	154 874	60	473 000	15 200
3-19-80	748 000	682 596	10 794	11 829	9.51	414 315	338 985	134 816	100	477 000	6 000
3-20-80	753 500	689 205	11 368	12 388	9.56	445 392	379 408	63 700	490	320 000	7 300
3-22-80	706 000	647 644	11 077	12 075	9.55	410 520	335 880	92 000	640	250 000	5 400
3-23-80	426 000	382 263	11 311	12 605	9.49	269 610	220 590	0	800	180 000	16 600
3-24-80	710 000	650 039	10 841	11 841	9.61	629 920	157 480	51 600	490	300 000	4 500
3-25-80	700 000	642 011	11 080	12 081	9.52	610 880	152 720	93 000	680	430 000	4 000
3-26-80	726 000	664 973	10 949	11 954	9.60	612 960	153 240	134 970	40	540 000	18 500

*This is only a rough measure of RDF weight.

†This value is derived from the average Btu content of each fuel.

TABLE 2.6. HEAT CONTENT OF FUELS USED AT THE AMES MUNICIPAL POWER PLANT DURING SAMPLING PERIOD

Duration of Test	Heat Content for each Fuel Type			
	Iowa Coal (Btu/lb)	Colorado Coal (Btu/lb)	RDF (Btu/lb)	Fuel Oil (Btu/gallon)
3-2-80 thru 3-16-80	8946	10,556	5587	138,603
3-17-80 thru 3-26-80	9035	10,298	6128	138,603

Fluctuations in the O_2, CO_2, and CO levels are usually indicative of process conditions in the boiler. The means for these components at Ames were fairly uniform, as can be seen from Table 2-7. The only unusual days were March 9, 15, and 23, as evidenced by high O_2 levels and low levels of CO_2 and CO. From Table 2-4, it can be seen that these were days of low electrical output and correspondingly high levels of excess air. Furthermore, these were the only days that were typical in this regard.

Although excess air was monitored in the plant's control room, it has also been calculated on a theoretical basis for comparison using the following expression

$$\%\ \text{excess air} = 100 \times \left[\frac{O_2 - CO/_2}{0.246\ N_2 - (O_2 - CO/_2)}\right]$$

where the gaseous components are expressed as percentages.

The results of these calculations are given in Table 2-8, along with the values of excess air measured in the control room. The calculated values are consistently smaller, and the same anomalies appear (i.e., large values on the 9th, 15th, and 23rd). In this case, the measured values are larger because these were taken after the air preheater to the boiler. Evidently, there is some air leakage in the preheater.

2.3.1 Air Preheater Leakage

Oxygen in the flue gas at the inlet and outlet to the preheater was monitored on March 8, 1980 to determine air preheater leakage. Continuous monitoring results are presented in Table 2-9. The oxygen readings were also plotted and are shown in Figure 2-1.

Examination of the plots in Figure 2-1 indicates that the increases and decreases in oxygen at the boiler exit are closely followed by similar increases and decreases in oxygen at the ESP inlet which is located downstream of the boiler. Since the variable oxygen readings at the inlet and outlet were taken on an intermittent basis, at 15 minute intervals, it was difficult to relate the data points at the boiler exit and the ESP inlet on a same time basis. However, from the graph the similar trends of the two curves can be easily observed.

TABLE 2-7. CONTINUOUS MONITORING DATA

Sampling Location	Date (1980)	O_2 (%) Mean	O_2 (%) σ	CO_2 (%) Mean	CO_2 (%) σ	CO (ppm) Mean	CO (ppm) σ	THC (ppm) Mean	THC (ppm) σ
ESP Inlet	3-2	4.6	0.34	12.7	0.44	17.9	1.61	<2	-
ESP Outlet		6.3	0.53	11.4	0.53	16.5	1.57	<2	-
Inlet	3-3	4.4	0.55	13.7	0.63	12.4	1.54	<2	-
Outlet		5.8	0.65	12.5	0.67	10.7	1.16	<2	-
Inlet	3-4	4.4	0.35	14.4	0.36	16.7	0.75	<2	-
Outlet		6.1	0.17	13.0	.19	14.7	.89	<2	-
Inlet	3-5	4.4	0.66	14.6	0.58	18.3	1.22	<2	-
		5.6	0.83	13.4	.36	27.8	10.14	<2	-
Inlet	3-6	4.3	0.29	13.9	0.37	16.7	2.30	<2	-
Outlet		DATA TAKEN FOR INLET ONLY							
Inlet	3-7	4.6	0.32	13.9	0.35	16.4	1.50	<2	-
Outlet		5.9	0.27	12.8	0.28	14.7	1.63	<2	-
Inlet	3-8	4.3	0.30	14.0	0.30	27.6	0.85	<2	-
Outlet		4.8	0.40	13.6	0.39	28.4	2.29	<2	-
Inlet	3-9	7.1	1.23	11.6	1.22	24.7	1.82	<2	-
Outlet		8.8	1.38	11.0	1.24	22.6	2.31	<2	-
Inlet	3-10	4.0	0.30	13.9	0.30	24.5	1.51	<2	-
Outlet		5.6	0.19	12.4	0.14	24.9	1.04	<2	-
Inlet	3-11	4.7	0.28	13.6	0.48	22.4	1.88	<2	-
Outlet		5.8	0.23	13.2	0.51	21.2	1.29	<2	-
Inlet	3-12	4.4	0.29	14.0	0.43	22.1	1.75	<2	-
Outlet		5.6	0.33	13.8	0.56	22.3	3.77	<2	-
Inlet	3-13	3.3	0.30	15.6	0.33	20.7	0.90	<2	-
Outlet		5.2	0.57	14.0	0.96	18.4	1.03	<2	-
Inlet	3-14	3.7	0.40	14.8	0.47	27.7	4.21	<2	-
Outlet		5.3	1.03	13.1	0.74	29.9	16.56	<2	-

(Continued)

TABLE 2-7. (Continued)

Sampling Location	Date (1980)	O_2 (%) Mean	O_2 (%) σ	CO_2 (%) Mean	CO_2 (%) σ	CO (ppm) Mean	CO (ppm) σ	THC (ppm) Mean	THC (ppm) σ
Inlet	3-15	6.3	1.56	12.6	1.45	22.0	2.03	<2	-
Outlet		8.4	1.87	10.7	1.67	18.7	2.01	<2	-
Inlet	3-17	3.7	0.47	14.4	0.62	21.5	1.73	<2	-
Outlet		5.4	0.32	12.9	0.33	20.0	1.41	<2	-
Inlet	3-18	3.8	0.33	14.4	0.46	23.3	1.18	<2	-
Outlet		5.4	0.30	13.0	0.40	23.7	9.62	<2	-
Inlet	3-19	3.8	0.58	14.7	0.72	23.6	1.84	<2	-
Outlet		5.3	0.47	13.2	0.47	26.2	17.55	<2	-
Inlet	3-20	4.1	0.29	14.3	0.41	20.1	2.21	<2	-
Outlet		5.9	0.25	12.8	1.11	17.4	1.70	<2	-
Inlet	3-22	3.6	.34	14.2	.35	38.3	25.81	<2	-
Outlet		5.4	.29	12.6	.46	37.7	22.61	<2	-
Inlet	3-23	5.9	1.09	12.7	1.08	NOT OPERATING		<2	-
Outlet		8.8	.75	10.1	.74	"	"	<2	-
Inlet	3-24	DATA TAKEN FOR OUTLET ONLY							
		5.4	.24	13.2	.24	"	"	<2	-
Inlet	3-25	4.4	.83	13.8	.71	"	"	<2	-
Outlet		5.4	.23	13.1	.26	"	"	<2	-
Inlet	3-26	4.9	.87	13.7	.73	"	"	<2	-
Outlet		DATA TAKEN FOR INLET ONLY							

TABLE 2-8. EXCESS AIR READINGS

Date	Excess Air %[1]	Excess Air %[2]
3-2-80	26.7	22.1
3-3-80	25.5	18.3
3-4-80	25.8	20.1
3-5-80	25.9	18.7
3-6-80	24.9	18.9
3-7-80	27.2	19.3
3-8-80	24.9	19.5
3-9-80	49.4	34
3-10-80	22.6	16
3-11-80	27.9	18
3-12-80	25.7	18
3-13-80	18.2	18
3-14-80	20.8	17
3-15-80	41.7	41
3-17-80	20.6	18
3-18-80	21.4	20
3-19-80	21.4	19
3-20-80	23.5	24
3-22-80	19.9	26
3-23-80	37.8	38
3-24-80	NA	16
3-25-80	25.6	18
3-26-80	29.5	18

[1] Based on continuous monitoring data from the ESP inlet

[2] Control room readings

TABLE 2-9. AIR PREHEATER CONTINUOUS MONITORING DATA

	Boiler Exit/Preheater Inlet				ESP Inlet/Preheater Outlet			
Time	% O_2	% CO_2	CO ppm	THC ppm	% O_2	% CO_2	CO ppm	THC ppm
1430	4.237	13.926	28	0.42				
1445					4.593	13.784	29	0.1
1500	4.094	14.222	27	0.49				
1515					4.975	13.542	28	0.22
1530	3.741	14.414	28	0.45				
1545					4.544	13.668	29	0.20
1600	4.637	13.678	28	0.37				
1615					4.901	13.520	27	0.19
1630	4.083	14.304	28	0.41				
1645					5.207	12.43	26	0.21
1700	4.089	13.972	26	0.22				
1715					4.879	13,538	26	0.15
1730	4.198	14.154	27	0.18				
1745					4.153	14.246	28	0.18
1800	4.192	13.740	26	0.23				
1815					5.141	13.574	26	0.18
1830	4.295	13.976	28	0.19				
1845					4.359	13.902	28	0.04
1900	3.937	14.154	29	0.22				
1915					4.959	13.564	27	0.25
1930	4.742	13.492	28	0.26				
1945					4.397	13.946	28	0.11
2000	4.632	13.566	28	0.21				
2015					4.401	13.558	36	0.18
Mean	4.24	13.97	27.58	0.304	4.71	13.61	28.1	0.168
	0.30	0.30	0.9	0.114	0.34	0.43	2.7	0.059

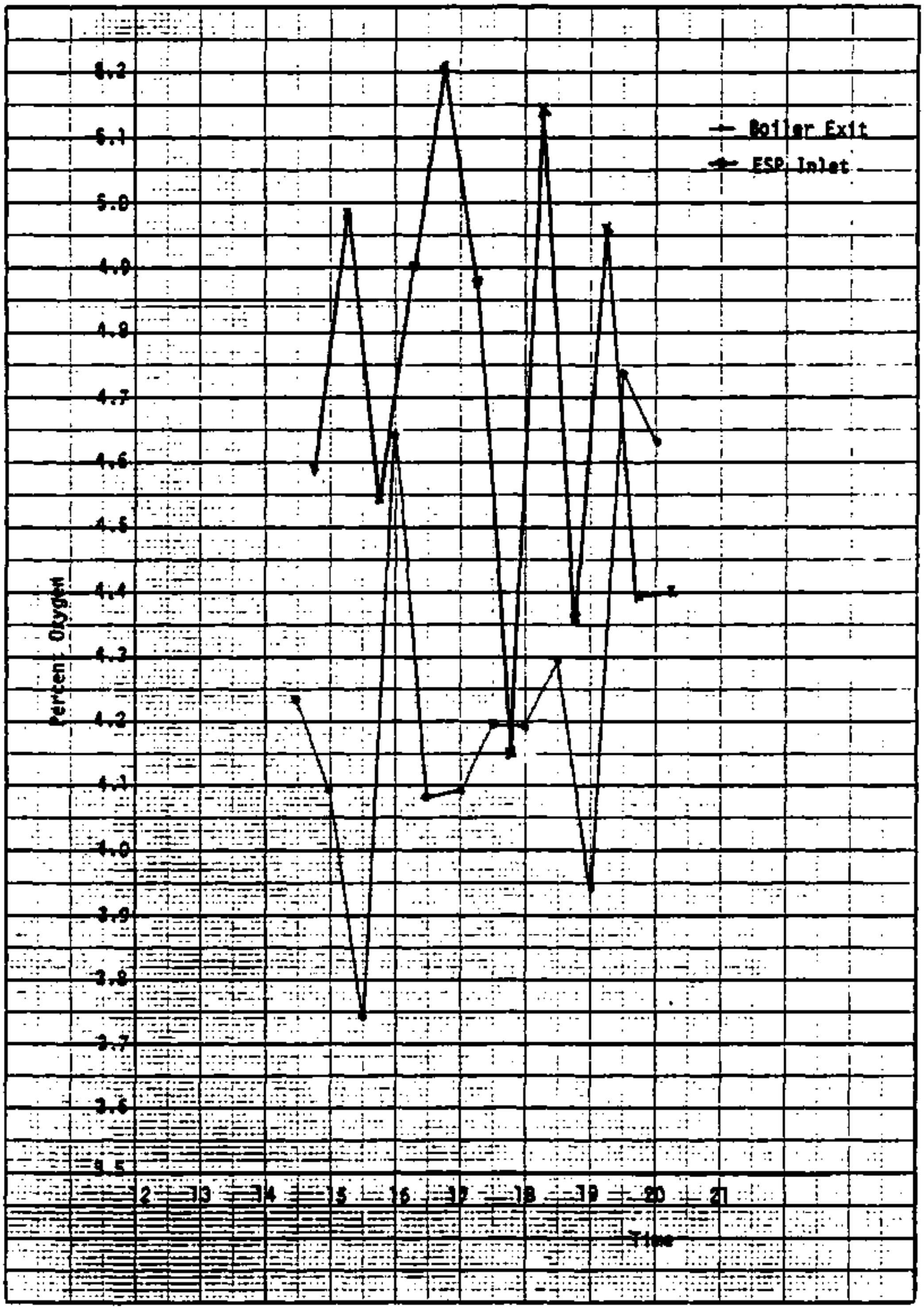


Figure 2-1. Oxygen in the gas before and after the air preheater

Air preheater leakage is defined as the ratio of the difference between the amount of flue gas out of the preheater and the amount of flue gas into the preheater to the amount of flue gas into the preheater. In order to estimate this leakage average values for oxygen for the inlet and outlet from the monitored data were used. Based on an average oxygen reading of 4.24 percent at the preheater inlet and 4.71 percent at the outlet an air preheater leakage of 2.9 percent was calculated. It must however be noted that during this period the boiler load averaged approximately 88% and the RDF heat input to the boiler was approximately 20 percent. Air preheater leakage will vary with the steam load and type of fuel fired.

3.0 SYSTEM DESCRIPTION

The coal-fired utility boiler tested was the No. 7 unit at the Ames Municipal power plant. The power plant is owned and operated by the city of Ames. Three boiler units, 5, 6, and 7, at the power plant have been modified to burn solid waste as a supplemental fuel with coal. Boilers 5 and 6 are Stoker-fired boilers and boiler No. 7 is a pulverized coal suspension fired boiler. Under normal operating conditions only unit No. 7 is used. Units Nos. 5 and 6 are operated only under peak demand conditions or when unit No. 7 is down.

The power plant is located within the city limits of Ames, Iowa. Ames is approximately 54 Km (34 miles) north of Des Moines. The Ames Municipal power plant layout is shown in Figure 3-1.

3.1 Boiler Description

Boiler No. 7 was designed to burn coal or natural gas as the primary fuel. It is a tangentially fired, pulverized coal, balanced draft, Combustion Engineering unit, rated at 175000 kg/hr (385,000 lb/hr) of steam. The generator is rated at 35,000 KW, gross. Unit No. 7 has been operating since June 1968. However, modification to burn refuse derived fuel (RDF) was made in 1975. Boiler No. 7 specification data is provided in Table 3-1 and a flow diagram of unit No. 7 is given in Figure 3-2.

As shown in Figure 3-2, coal from the plant stockpile is fed to two Raymond Bowl Mill pulverizers. Air preheated to about 340°C (650°F) by the combustion gases is supplied to the pulverizers to dry the coal, and to convey the pulverized coal to the burners. Pulverizer air preheat is necessary to prevent pulverizer to burner blockage which can be caused by wet fuel. Design specifications of the Raymond Bowl Mill pulverizer are provided in Table 3-2.

Pulverized coal entrained in 15 to 20 percent of the total combustion air is conveyed to the individual burner nozzles which direct the coal and primary air into the combustion chamber. Combustion air is supplied to the boiler unit by a Westinghouse forced draft fan. The combustion air drawn

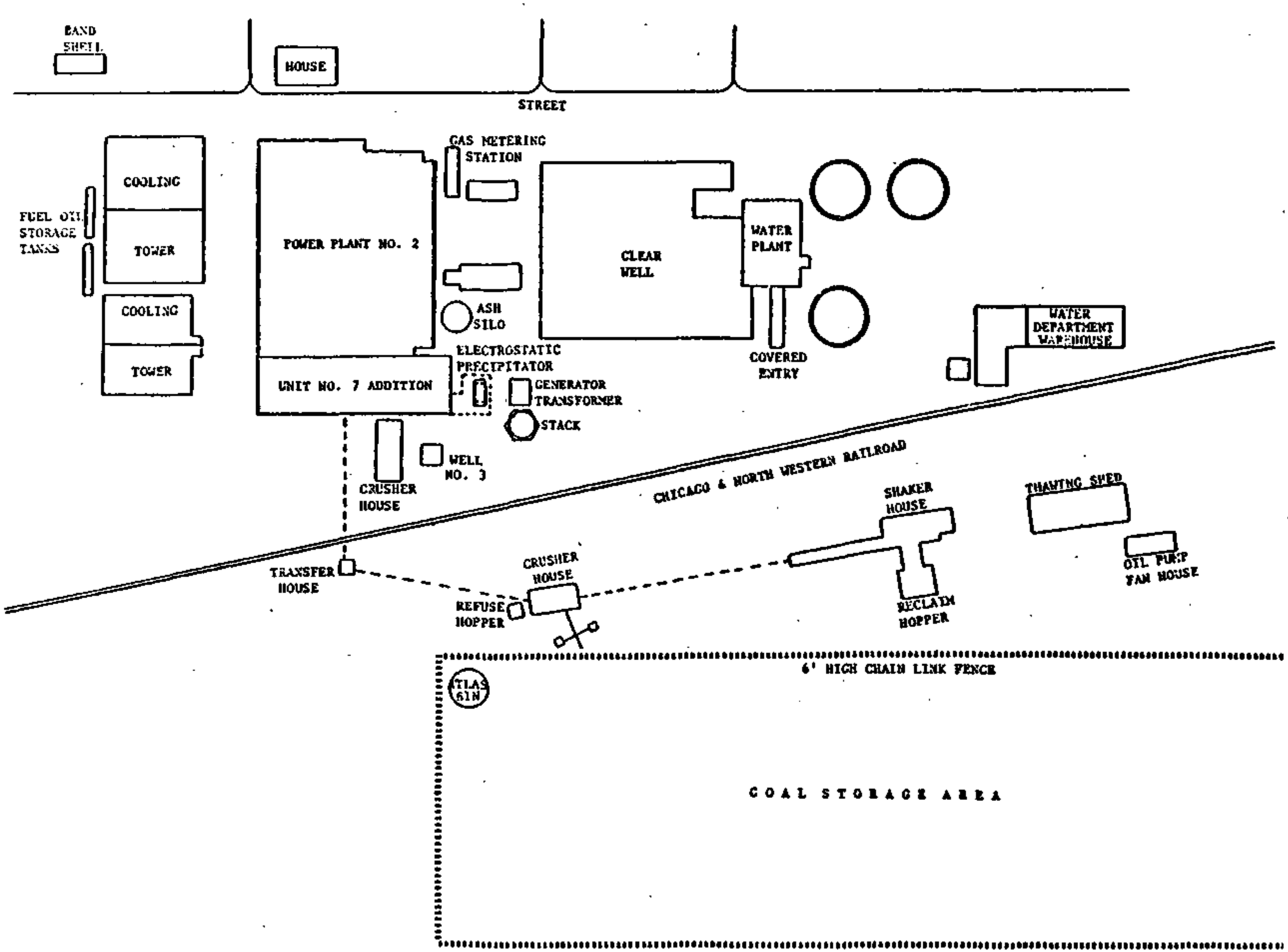


Figure 3-1. Layout of plant site

TABLE 3-1. BOILER DESIGN DATA

Description	Size
Design pressure, psi	1085 psig
Total effective heating surface sq ft	
Boiler	16550
Furnace EPRs	6200
Superheater - Convection zone	5200
Radiant zone	1800
Economizer	None
Regenerative Air Heater	67200
Air Preheating Coil	5070
Furnace Volume, cubic feet	27300
Furnace width and depth	19'-11" by 19'-11"
C to C of tubes, ft	
Furnace design pressure, in H_2O positive	8" WG
Total weight complete, lb	2,340,000
Water required to fill boiler and water walls to operating level, gal	Approx. 17,900 U.S Gallons
Inside diameter and thickness of steel drum	66" DIA - 4 $\frac{13}{16}$" x 2 $\frac{13}{16}$"
Overall length of steam drum	Approx. 27' - 0"
Drum head thickness, in lifting weight of drum safety valves	2 1/4" 66" Ø Drum = 85000 LBS
Manufacturers, type, number and size of drum safety valves	Consolidated Two (2) 3" #1757A
Manufacturer, type, number and size of blowdown valves	Two (2) sets 2" Yarway 6968-81
Tubes in furnace	
Size and thickness	2 1/2" O.D. x .180
Water well tube spring, in C to C	3" all wells
Furnace exit first row tube spring, in C to C	9" (Finishing superheater)
Are tubes staggered?	NO - IN LINE
Material	SA - 192
Number	26 Assemblies
Tube spring in C to C	9" (Finishing superheater)
Tubes in Boiler	
Size and thickness	2 1/2" O.D. x .12
Material	SA -192
Tube spring C to C (in)	3 3/4" Transverse
Number	1472
Circulation ratio, minimum	Water walls - 10 to 1

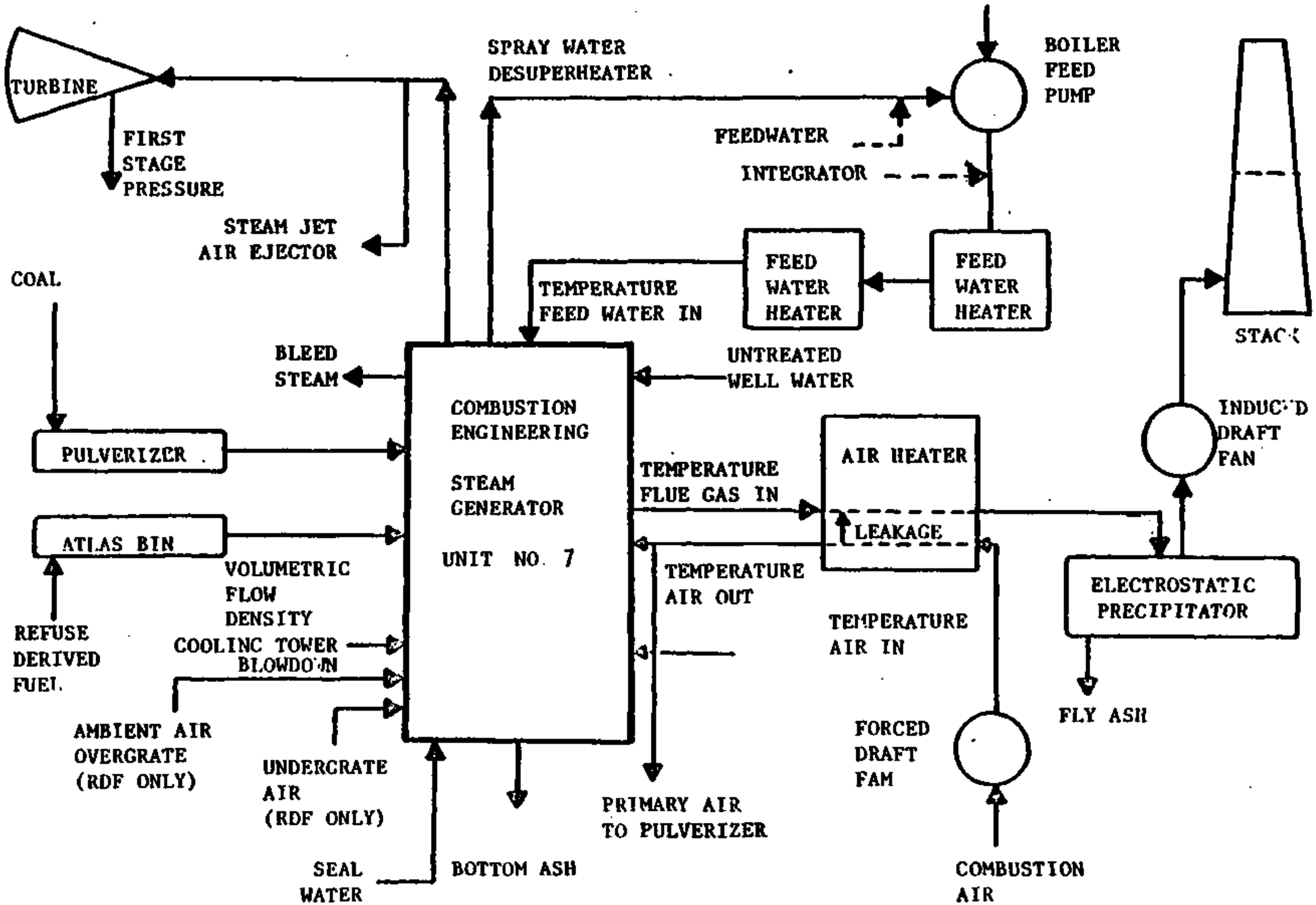


Figure 3-2. Flow diagram for unit #7 at Ames Municipal power plant

TABLE 3-2. DESIGN SPECIFICATION FOR RAYMOND BOWL PULVERIZERS

DESCRIPTION	SIZE
Pulverizers	
Manufacturer's Model No.	C. E. Raymond No. 613
No. of pulverizers	Two (2)
Type and size	Bowl Mill
Weight including driver	Approx. 98500 LBS each journal assembly
Weight and dimensions of largest piece requiring removal for maintenance	3 x 4 x 4 ft 3900 LBS.
Minimum stable firing rate, lb per hr each of specified coal	8000 LBS/HR
Maximum firing rate, lb per hr of specified coal each	32000 LBS/HR @ 60 GR 17.12% M
Maximum turndown ratio	Pul. - Burner Combination 4 to 1
Maximum horsepower input required	265 each Shaft Incl. Exhauster
Primary air temperature, F.	
For the specified coal	651
Max. allowable	750
Maximum boiler load with one pulverizer in operation with specified coal, no gas firing, lb per hr	250,000

by the forced draft fan is obtained from the 9th floor of the power plant building (refer to Figure 3-3). Design specifications for the forced draft fan are provided in Table 3-3. The burners are designed to admit controlled quantities of additional air through separate air ports surrounding or built into the fuel nozzle.

In the combustion chamber, the combustible matter reacts with oxygen of the air to release thermal energy at temperatures exceeding 1100°C (2000°F). The walls of the combustion chamber are lined with water-filled tubes which absorb thermal energy and generate steam. The water tubes are filled with liquid or vapor, depending on pressure and temperature conditions.

Heat transfer in the combustion chamber cools the combustion gases. The cooler combustion gases flow from the combustion chamber to the superheater where further heat transfer and gas cooling occurs. The superheater is a combination Radiant-Convection type with 13 tube rows and 26 steam passes on the primary side and 26 tube rows and 52 steam passes on the secondary side. The maximum design temperatures in the superheater are: steam side - 350°C (primary), 485°C (secondary); gas side - 1150°C (primary), 1050°C (secondary); and outside metal surface - 470°C (primary), 545°C (secondary). Steam superheat is necessary for thermodynamic efficiency and also to prevent steam condensation which would damage the blades of the steam turbine.

Combustion gases from the superheater normally flow to the economizer section where heat is transferred to the boiler feed water. However, the No. 7 unit has no economizer and flue gases from the superheater flow to the air preheater, then to a cold-side electrostatic precipitator via an induced draft fan (refer to Table 3-3) out through the stack. The regenerative air heater has an effective heat exchange surface area of 67200 sq ft. Combustion gases enter the air heater at texperatures of 370° to 400°C (700 to 750°F) and exit at temperatures of 135° to 150°C (280 to 300°F). Air temperature entering the air heater ranges from 35° to 50°C (100 to 120°F) and exit temperatures range from 315° to 335°C (600 to 640°F). Performance characteristics for unit No. 7 provided by the manufacturer are given in Table 3-4.

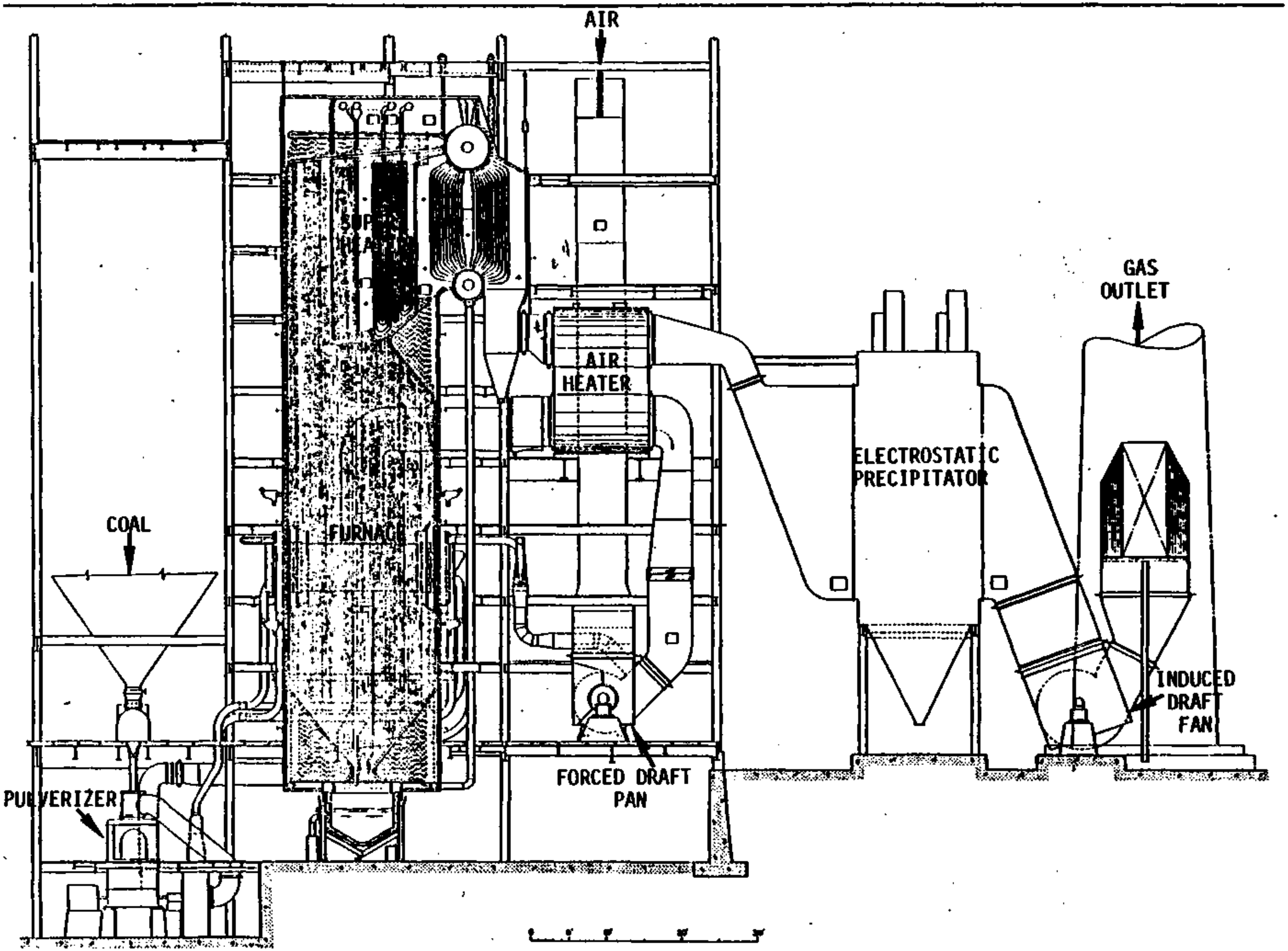


Figure 3-3. Schematic of Ames Municipal power plant boiler No. 7.

TABLE 3-3. FAN DESIGN PERFORMANCE

Forced Draft Fan	
Manufacturers name	Westinghouse
Model No.	#4054
Blade type	Air foil
Operating speed, rpm	1180
Air inlet temperature, °F	80°
Air flow (100% load), lb/hr	422,696
Air flow (100% load), ft^3/min	99,934
Fan static pressure, psi	0.28
Static efficiency (100% load), %	54.6
Power required, Kw	167.1
Induced Draft Fan	
Manufacturers name	Westinghouse
Model No.	#4073
Blade type	Air foil
Operating speed, rpm	885
Air inlet temperature, °F	279
Air flow (100% load), lb/hr	482,653
Air flow (100% load), ft^3/min	153,900
Fan static pressure, psi	0.26
Static efficiency (100% load), %	52.3
Power to fan shaft, Kw	249.9

TABLE 3-4. PREDICTED PERFORMANCE CHARACTERISTICS OF UNIT #7 AT AMES MUNICIPAL POWER PLANT.

FUEL		COAL	COAL	COAL
Evaporation	lb/hr	216,000	360,000	385,000
Feedwater Temperature	F	375	428	433
Superheater Outlet Temperature	F	905	905	905
Superheater Outlet Pressure	psig	900	900	900
Superheater Pressure Drop	psi	30	75	85
Gas Drop, Furnace to Econ. Outlet	"wg	0.85	1.85	2.15
Gas Drop, Econ. Outlet to A.H. Outlet	"wg	2.00	4.35	4.90
Gas Temp. Entering Air Heater	F	705	732	743
Gas Temp. Leaving Air Heater, Uncorr.	F	281	296	297
Gas Temp. Leaving Air Heater, Corr.	F	265	279	280
Air Temp. Entering Air Heater	F	119	101	99
Air Temp. Leaving Air Heater	F	598	633	635
Air Press. at F.D. Fan	"wg	5.10	7.75	8.70
Ambient Air Temperature	F	80	80	80
Excess Air Leaving Economizer	%	22	22	22
Fuel Fired - Coal @ 9506 BTU/#	lb/hr	28,600	45,600	48,500
Efficiency	%	87.99	87.28	87.21

Superheat steam temperature control range is from 216,000 to 385,000 lb/hr.

The fuel specifications on which the above are based are as follows:

F.C.	37.10	HHV (as fired) 9506 BTU/#
V.M.	32.27	
Ash	13.51	
Moist.	17.12	
	100.00%	

Unit No. 7 generally burns a mixture of Iowa coal, Colorado coal, and refuse derived fuel (RDF). The ratio of the two types of coal in the mixture varies. However, during the test program a 55 to 45 percent ratio of Iowa and Colorado coal was maintained in the pulverized coal mixture. Approximately 20 percent of the total fuel fired is RDF and 80 percent pulverized coal.

Coal is stored in the coal yard in two separate piles. Front-end loaders are used to move the coal to the transport conveyor feeding the storage bunker. Coal is alternately moved to the conveyor and is overlayed in the bunker prior to the coal dropping into the pulverizer. This mixing of coal is done on a weight basis and has proven satisfactory to the plant in maintaining the proper blend.

RDF is produced at a separate Ames city facility located approximately two blocks away. All of the RDF produced is pneumatically conveyed to a storage bin (Atlas bin) 25 m (85 ft) in diameter with a holding capacity of 454 Mg (500 tons). The RDF is fed from the Atlas bin at the required rate (8.5 tons/hr maximum) and pneumatically conveyed to the RDF burners. There are two RDF burners located approximately 61 cm (24 inches) below the coal burners at opposite corners of the firebox. The location of the RDF burners is shown in Figure 3-4.

The by-products of combustion are stack gases and ash. With pulverized-coal firing, all of the burning is accomplished in suspension with the result that about 80 percent of the ash remains in the flue gases. Due to the utilization of REF to supplement coal as fuel, modifications were made to the boiler. Grates were installed in April 1978 to assist in the combustion of RDF. Prior to the installation of the grates, RDF burning in suspension was not very effective, and substantial portions of the RDF dropped unburnt into the bottom ash hopper.

Deposited ash and slag in the boiler furnace bottom are removed at least 3 times per day. An average of 758,000 liters/day (200,000 gallons/day) of sluice water (raw well water) is used to remove the solid waste from the furnace bottom. This waste is then drained to a holding pond where the ash is dredged out. The water from the holding pond percolates through the soil eventually into the nearby Skunk river. Any overflow from the holding pond

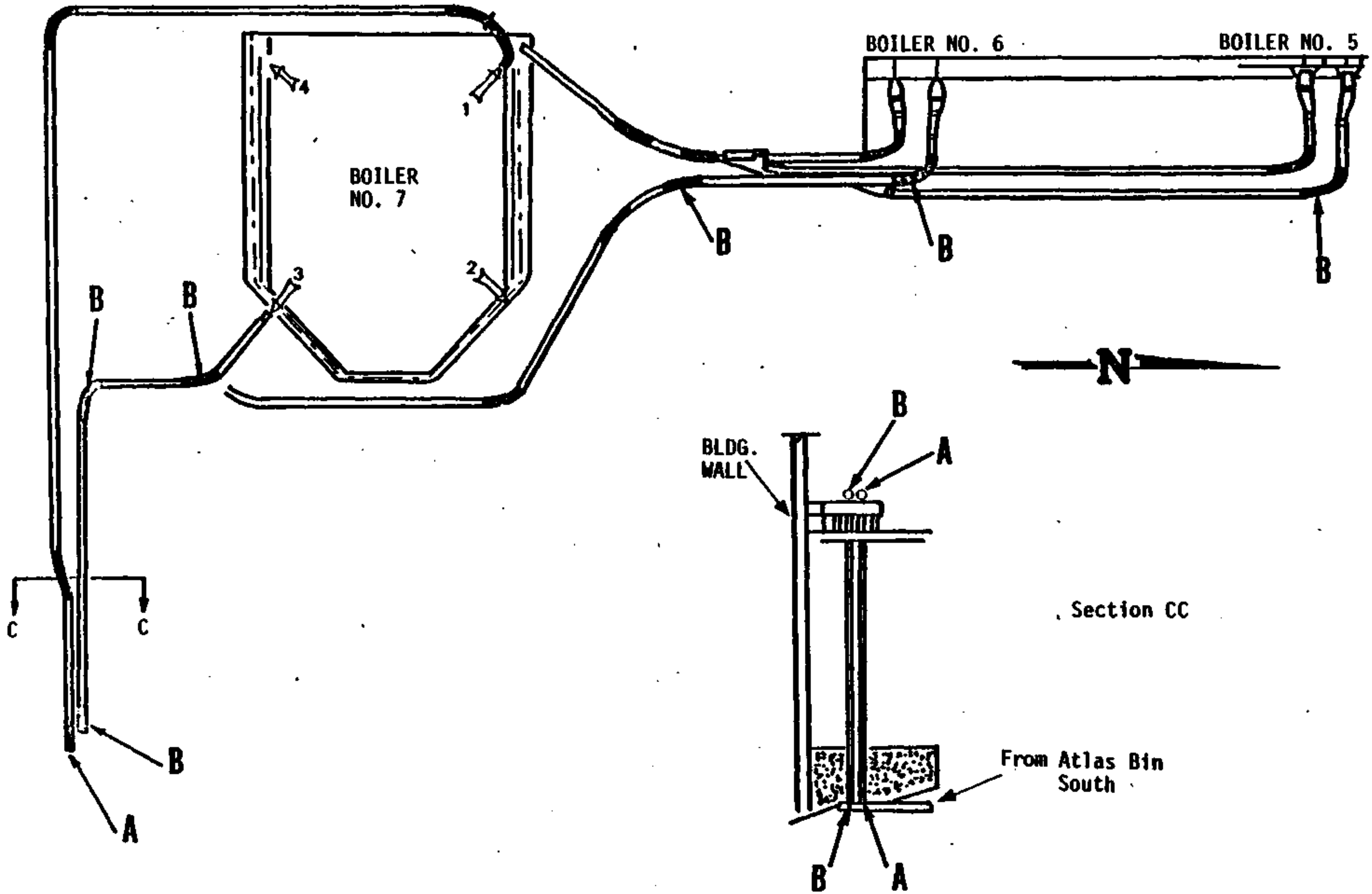


Figure 3-4. Solid waste recovery system

is also absorbed by the river. Also deposited in the holding pond is the electrostatic precipitator (ESP) fly ash. The fly ash from the ESP hoppers is pneumatically conveyed (3 times per day) to the bottom ash hopper drain system which transports it to the holding pond. The dredged ash is stored on site in piles.

Make up water for the boiler is obtained from the city water supply. Boiler feedwater is processed by water softeners and deaerators and treated with caustic soda, phosphates and hydrazine to prevent scaling and corrosion. Tannin is also added to maintain particles in suspension.

Normal operation of the boiler is 24 hours per day, 7 days per week. The boiler is scheduled to be offline once per year for 10 to 14 days for various types of maintenance.

3.2 Electrostatic Precipitator

Flue gases from the air heater are treated in an electrostatic precipitator (ESP) for the removal of particulate matter. The ESP in unit No. 7 is an American Standard Model 371. It is a wire/plate type with rappers and is designed to handle 4900 m^3/min (175000 cfm) of gas at an average inlet dust loading of approximately 9.27 gm/m^3 (4 gr/scf). The ESP has 4 cell units with 2 fields and 8 insulator compartments. Performance characteristics for the ESP are given in Table 3-5.

The collection system of the ESP has an effective surface area of 2030 m^2 (21840 sq ft) with 28 gas passages having a space of 23 cm (9 inches) each. The collecting surface area rappers are of the electric vibrator type and the maximum collecting surface area rapped at one instant is 113 m^2 (1215 sq ft). Total hopper capacity is 48 m^3 (1700 cubic feet) with overall dimensions of 5.2 m x 6.8 m x 18.1 m (17' x 22.5' x 59.5').

The electrical system of the ESP requires a maximum operating voltage of 45 KV. Power requirement at maximum demand is 83 KVA and the total connected load is 61 KW. There are 8 electric vibrator type high voltage rappers and two rectifiers. The two rectifiers are rated at 45 KV each.

The primary voltage is approximately 260 volts at the inlet field and 200 at the outlet field. The primary current is approximately 52.0 amps at the inlet field and 34 amps at the outlet field. The secondary voltage and currents average 34.0 KV, 35 ma and 29.0 KV, 80 ma at the inlet and outlet fields respectively. The spark rate averages around 120 per minute at the inlet field and 145 per minute at the outlet field.

TABLE 3-5. PERFORMANCE CHARACTERISTICS OF THE AMERICAN STANDARD ESP

Performance at 385,000 lb/hr load, coal fuel	
Gas to ESP cfm	167,000
Gas to ESP, lb/hr	510,000
Gas Temp °F	300
Inlet dust loading, gr/cf	3.7
Outlet dust loading, gr/cf	0.074
Efficiency, %	98
Gas velocity, fpm	266
Pressure drop, in. H_2O	0.5
Time of gas contact, sec.	2.94

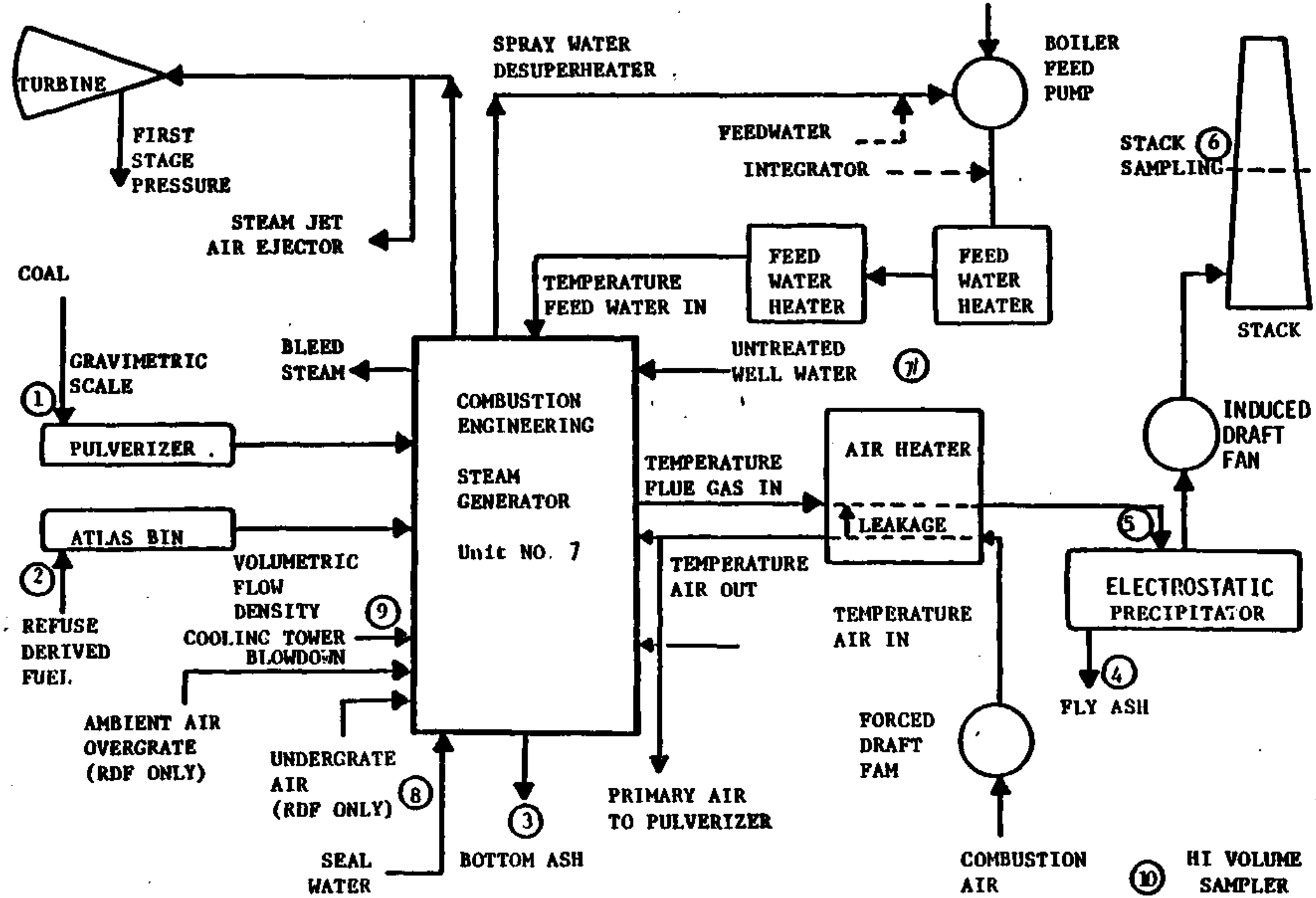
4. SAMPLING LOCATIONS

All sampling locations are identified in Table 4-1 and Figure 4-1. Figure 4-2 is a cross sectional schematic depicting the traverse point locations at the stack. Figure 4-3 is a horizontal view of the ESP inlet showing port locations, and Figure 4-4 is a cross sectional view of the ESP inlet depicting the traverse point locations.

The continuous monitoring probe was located on the North side of the ESP inlet duct prior to the gas sampling ports and at a depth of approximately 4 feet. At the stack, the monitoring probe was alternated between ports 2 and 3 and at a depth of 4 feet. These two ports were also used for the gas sampling trains.

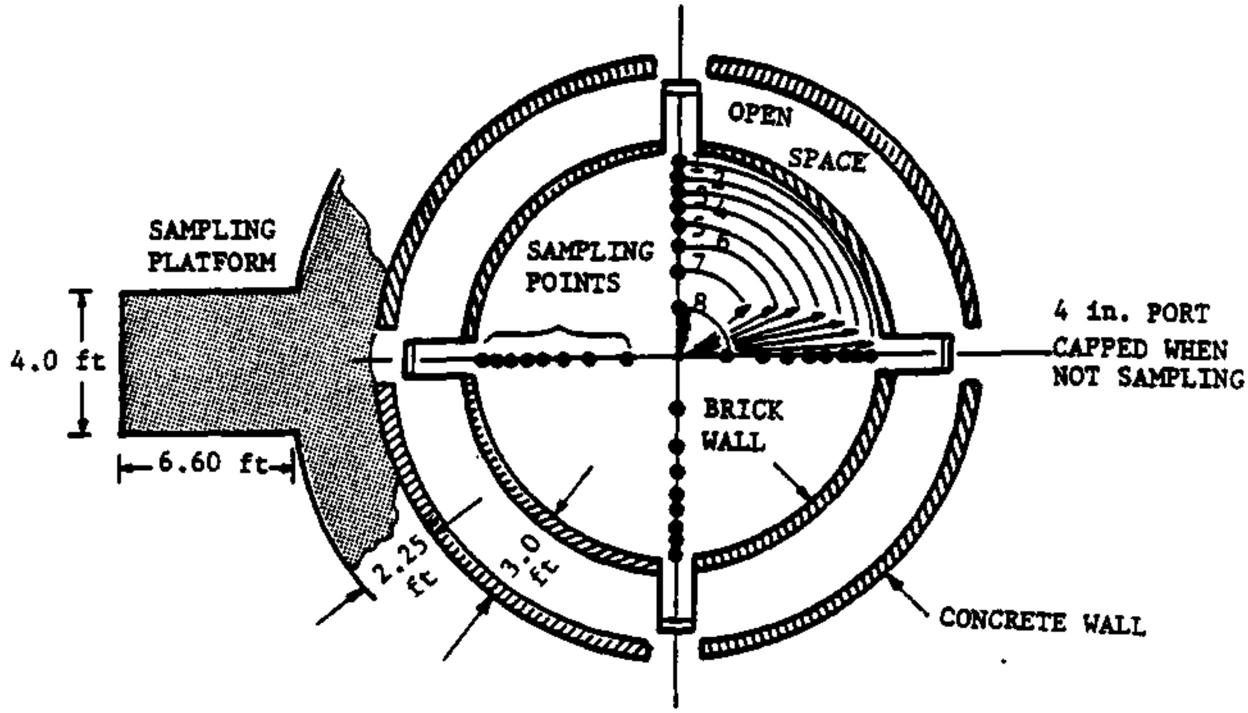
TABLE 4-1. SAMPLING LOCATIONS

Solid Sample Locations	
1	Blended Coal
2	Refuse Derived Fuel
3	Bottom Ash
4	Fly Ash
Gaseous Sampling Locations	
5	ESP Inlet
6	Stack
10	Hi Volume Ambient Air Sampler
Liquid Sample Locations	
7	Untreated Well Water
8	Seal Water
9	Cooling Tower Water



Source: Compliance test report data prepared by Iowa State University Engineering Research Institute personnel under the direction of Dr. J. L. Hall, et al. from tests conducted during Sept. 1978.

Figure 4-1. Unit 7 flow diagram and measurement locations.



NOT TO SCALE

SAMPLING POINTS

TRAVERSE POINT NUMBER	DISTANCE FROM OUTSIDE EDGE OF STACK IN	DISTANCE FROM OUTSIDE EDGE OF STACK CM	POINT	DISTANCE FROM OUTSIDE EDGE OF STACK IN	DISTANCE FROM OUTSIDE EDGE OF STACK CM
1	38.2	97.03	5	59.4	150.88
2	42.8	108.71	6	66.4	168.66
3	47.8	121.41	7	75.	190.75
4	53.2	135.13	8	87.8	223.01

Figure 4-2. Cross Section of stack showing traverse point locations.

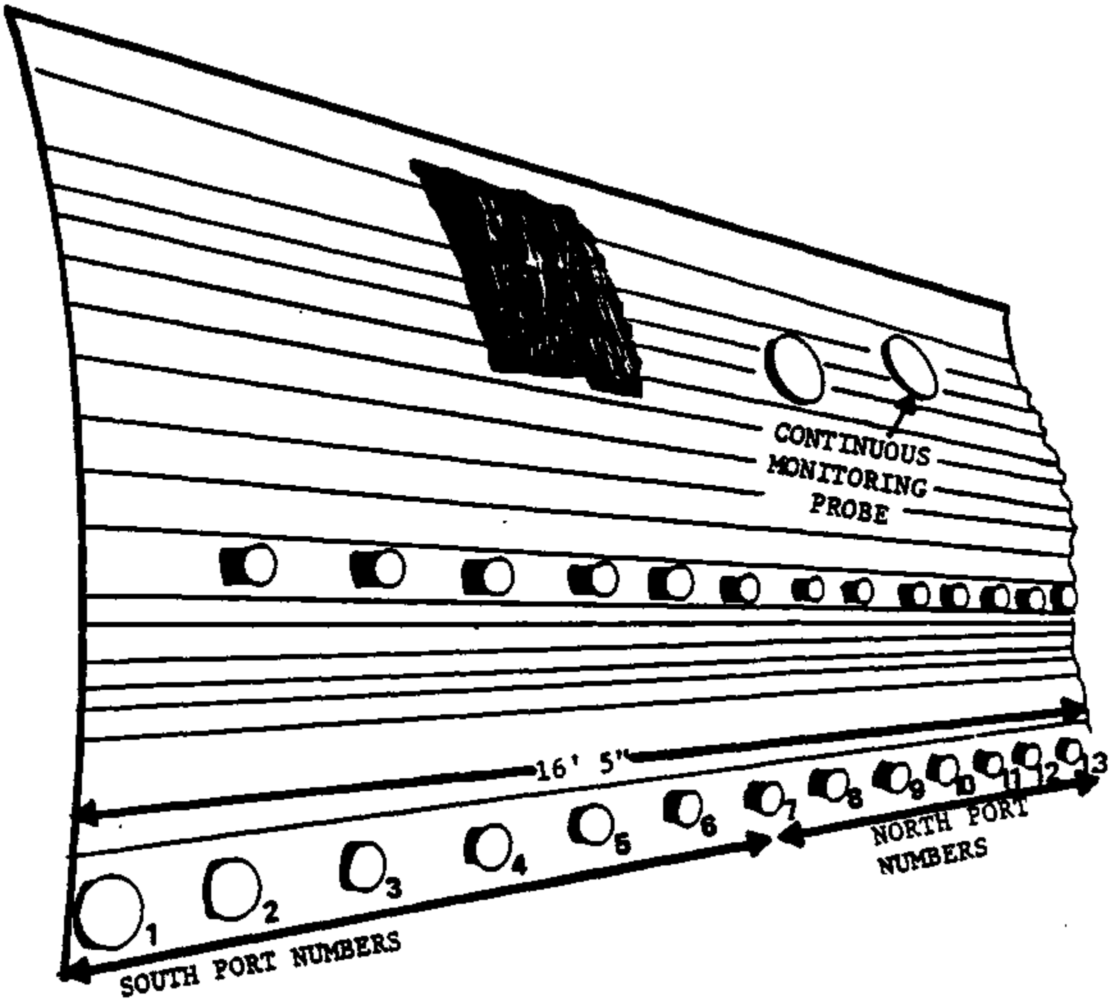
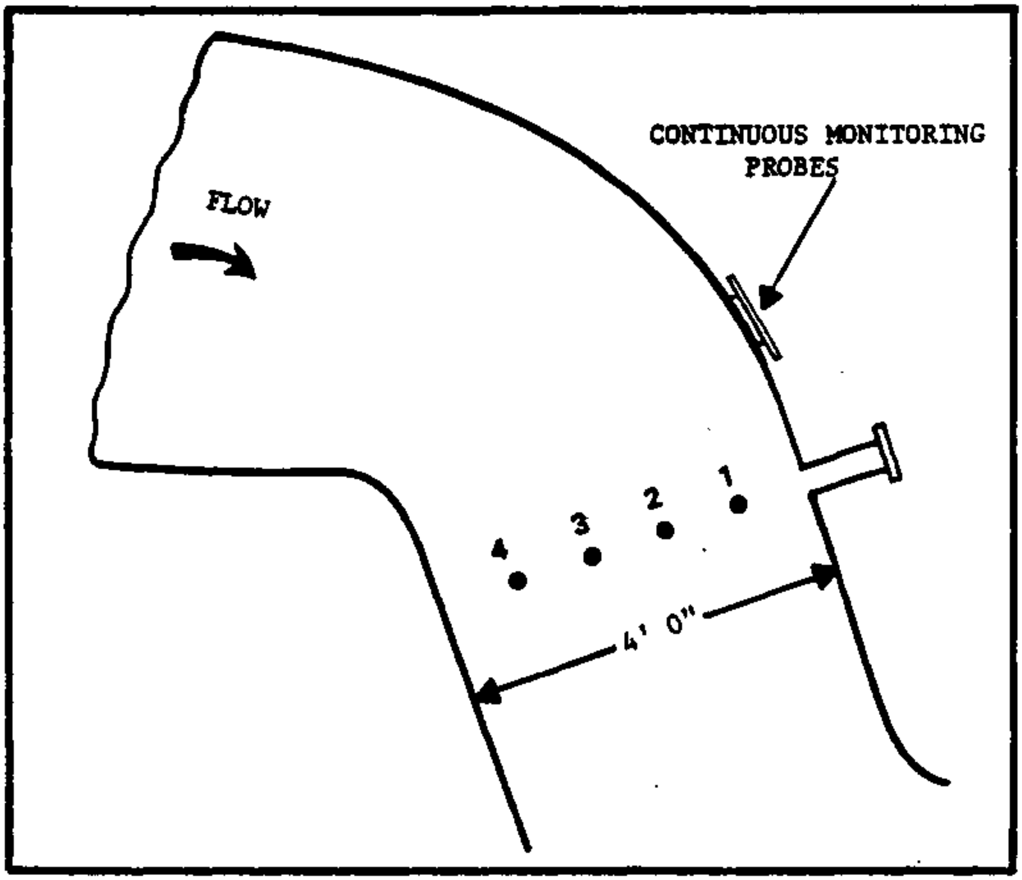


Figure 4-3. Inlet Duct - Showing Port Locations



Traverse Point Number	Traverse Point Location From Outside of Nipple	
	Inches	Centimeters
1	22	53.9
2	34	83.3
3	46	112.7
4	58	142.1

Figure 4-4. Inlet Traverse Point Locations

5.0 SAMPLING

This section includes information on the sampling program conducted at the Ames facility. Any changes or pertinent comments are included in this section.

5.1 Gas Sampling

The flue gas sampling at the Ames facility was performed at the electrostatic precipitator inlet and at the stack.

Sampling for organics was to be performed for fourteen consecutive days with an additional three days sampling for particulate cadmium. However, due to extreme weather conditions the program was modified to collect nine inlet and outlet gas samples. Sampling for organics was accomplished concurrently at the inlet and outlet utilizing two modified method 5 trains (Figures 5-1 and 5-2) at both sampling locations. Inorganic cadmium was only sampled at the stack and utilized one standard Method 5 train, Figure 5-3.

The sampling crew collected a ten m^3 (10 ± 1 m^3) sample by extracting the flue gas at a rate approximating the flue gas velocity. The particulate matter was collected in a cyclone and on the filter media. The gas stream was passed through an XAD-2 resin trap to absorb the organic constituents. and through an impinger system to condense any moisture present in the gas. Parameters such as temperatures, pressures, and gas volumes were monitored throughout the sampling period. The sample fractions were recovered from the sampling trains and turned over to an MRI representative. The outlet (stack) sampling position was sampled with no change to the sampling plan while the ESP inlet sampling was modified.

- <u>ESP Inlet</u>

  During the initial tests, it was found that the outermost ports exhibited little or no flow. At one point of the traverse, the velocity head (ΔP) was negative while the next point indicated positive ΔP, thereby cancelling each other. It was therefore recommended that these two outer ports be dropped from the test. The recommendation was accepted and implemented as part of the test program.

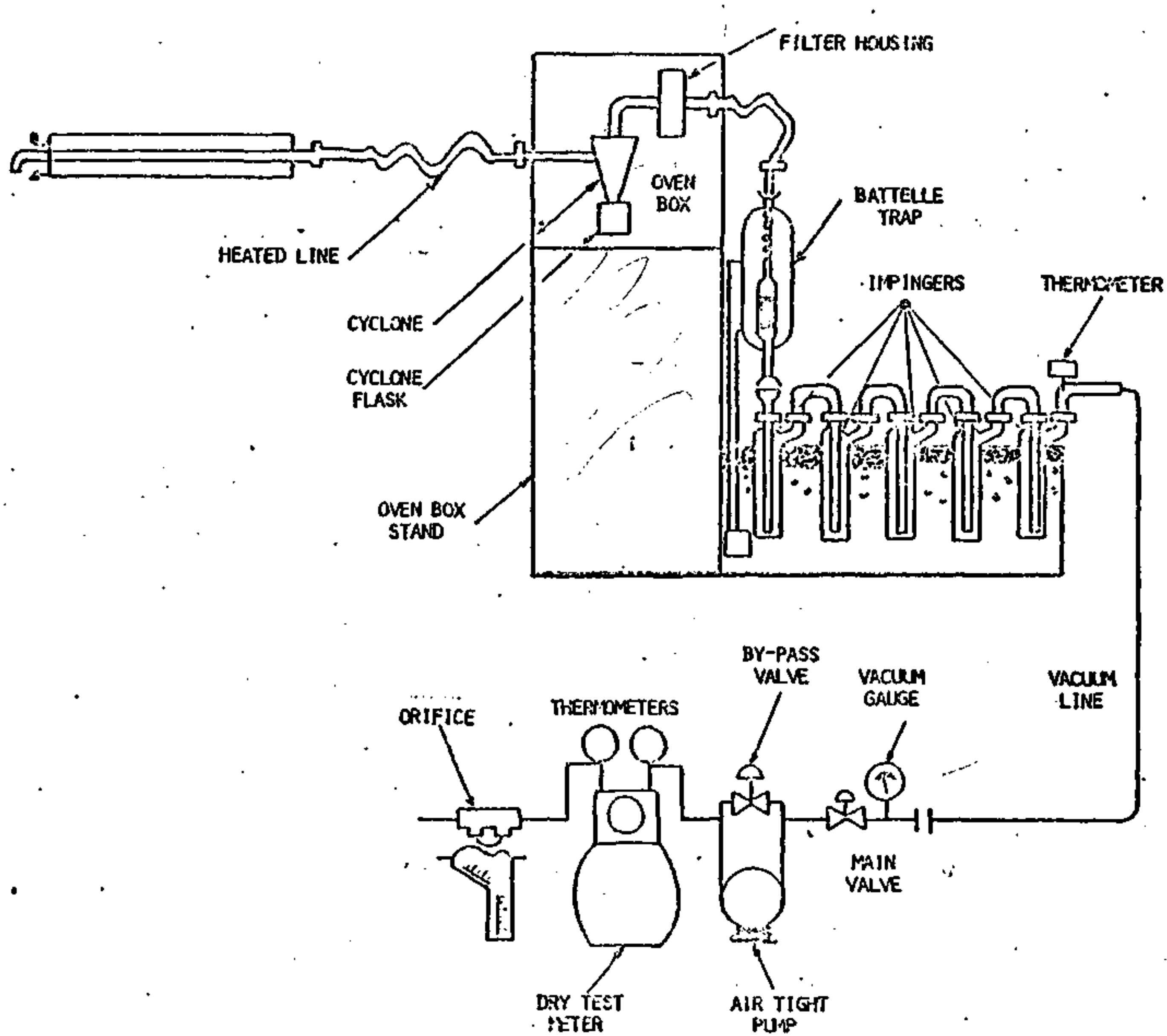


Figure 5-1. ESP inlet sampling train

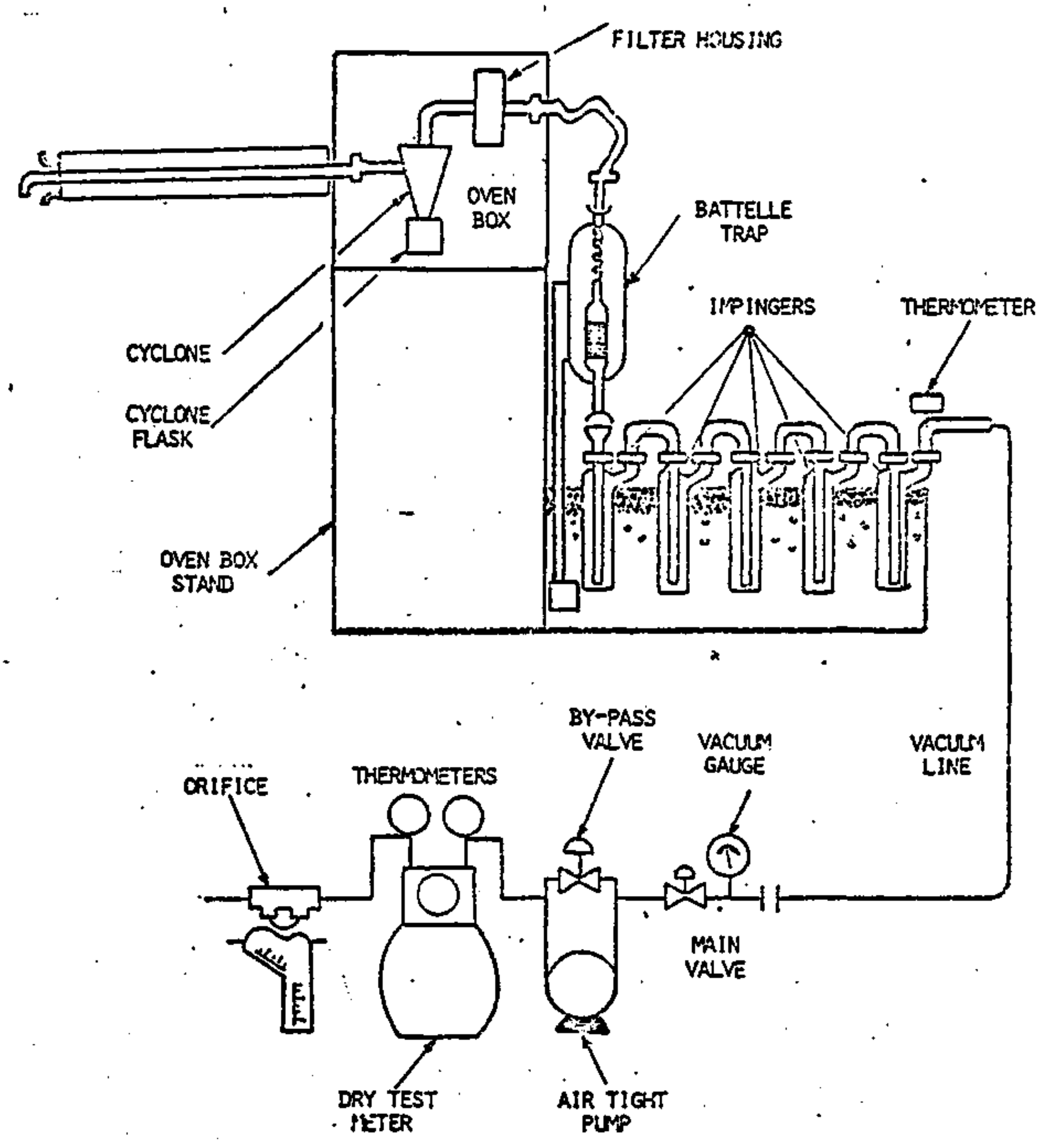


Figure 5-2. Stack sampling train

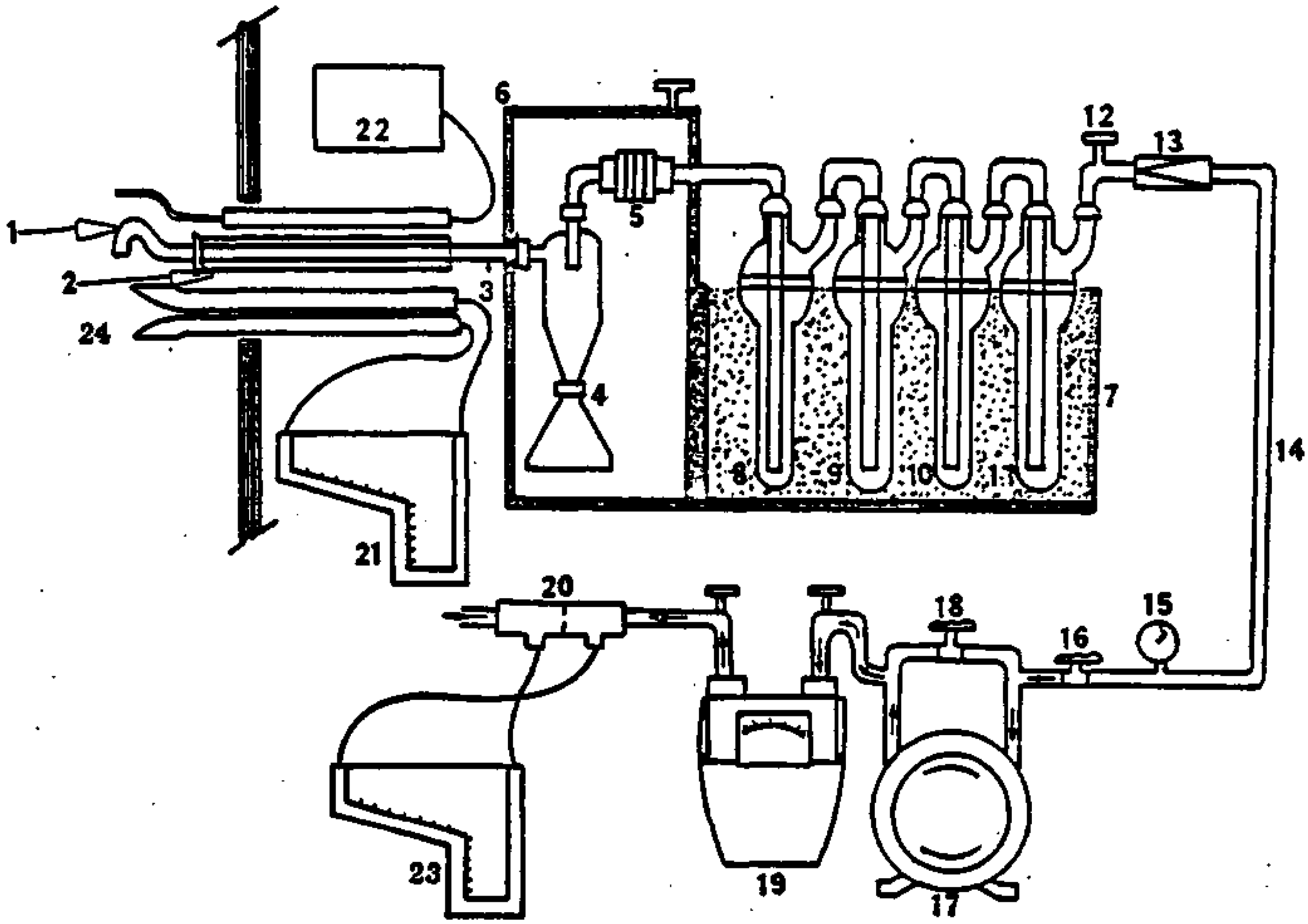


Figure 5-3. EPA Method 5 particulate sampling train

1) Calibrated nozzle
2) Glass lined probe
3) Flexible teflon sample line
4) Cyclone
5) Filter holder
6) Heated box
7) Ice bath
8) Impinger (water)
9) Impinger (water)
10) Impinger (empty)
11) Impinger (silica gel)
12) Thermometer
13) Check value
14) Vacuum line
15) Vacuum gauge
16) Main value
17) Air tight pump
18) Bypass value
19) Dry test meter
20) Orifice
21) Pitot manometer
22) Potentiometer
23) Orifice manometer
24) S type pitot tube

5.2 Solid Sampling

During each test day, four solid streams: coal, precipitator ash, bottom ash, and refuse derived fuel (RDF) were sampled six times per day following a schedule set up by Research Triangle Institute (RTI). The sampling was coordinated between RTI, the sampling crew and power plant personnel. The schedule provided the basis for collection of unbiased samples by obtaining a random selection from the multiple sources available for sampling. This approach was taken to avoid any cyclic biases which might have been present in the daily operation of the power plant. The samples and their sampling frequencies were:

- The coal samples were taken from the feed line leading from the storage bunkers into the gravimetric feeders supplying the coal pulverizers. A metal scoop was used to remove the sample from the feed line and transfer it to the sample containers.
- The precipitator ash was removed and collected from the bottom of the precipitator hoppers. A metal scoop was used to remove the sample from the access pipe and transfer it to the sample container. The hoppers were pneumatically evacuated after each sample was taken. A visual inspection was made to insure complete evacuation of ash from the hoppers.
- The bottom ash samples were collected from the base of the furnace. These samples were collected wet with a high solids content from the furnace floor prior to sluicing out the ash by plant personnel. The ash doors were open during the washing procedure and the ash sample was scooped up in a teflon line pan and transferred to the sample container with teflon lined forceps before the furnace floor was washed with water to remove the ash. To provide representative samples of ash, as distributed over the entire rectangular base of the furnace, the area of the furnace floor was divided into an equal-area grid system. The samples were scooped from a specific grid area as provided by Research Triangle Institute each time a sample was taken.
- The RDF samples were taken from the feeders in the Atlas bin prior to being pneumatically conveyed to the boiler furnace for firing. The material was placed into sample containers from a specific feeder and returned to the recovery area for labeling. Protective clothing was worn within the feeder area and plant personnel were notified when entering and leaving the area.

5.3 Liquid Sampling

Three liquid streams were sampled during the course of the test program: cooling tower blowdown, well water, and bottom ash seal water (overflow water). Liquid streams which did not have continuous flows, were allowed to purge for three minutes prior to obtaining samples. Sample containers were rinsed three times with sample liquid prior to being filled with that liquid. The streams sampled and frequency of sampling were as follows:

- Seal water was sampled twice per shift, for a total of six samples per 24 hour period.
- Cooling tower blowdown was sampled once per day.
- Three well water samples were collected over the testing period.

Appendix C contains the time frequency schedule utilized by members of the solid and liquid sampling team.

5.4 Hi Volume Sampler

To monitor the ambient air background, a high volume ambient air sampler (Figure 5-4) was used. It was placed on the roof of the Ames facility to obtain a representative background utilizing outside ambient air rather than sampling air inside the building that could have been contaminated or influenced by the combustion process.

5.5 Quality Assurance

A quality assurance sample was also taken of the final test day. To collect the quality assurance sample, two sampling trains were placed at the same point in the same port at the inlet of the ESP. No traversing was performed. Both trains were run at the same isokinetic rate for the same duration as a normal test day. Also during the Q/A day, solids and liquids were collected as in a normal test day.

5.6 Sampling Train Background

To obtain the train background (blank) an entire sampling train, including resin trap filter and impinger solutions was set up at the ESP inlet. The train was taken to normal operating temperatures and allowed to remain at these temperatures for one (1) hour. All train components were recovered as a normal run and all sample blanks were given to an MRI representative.

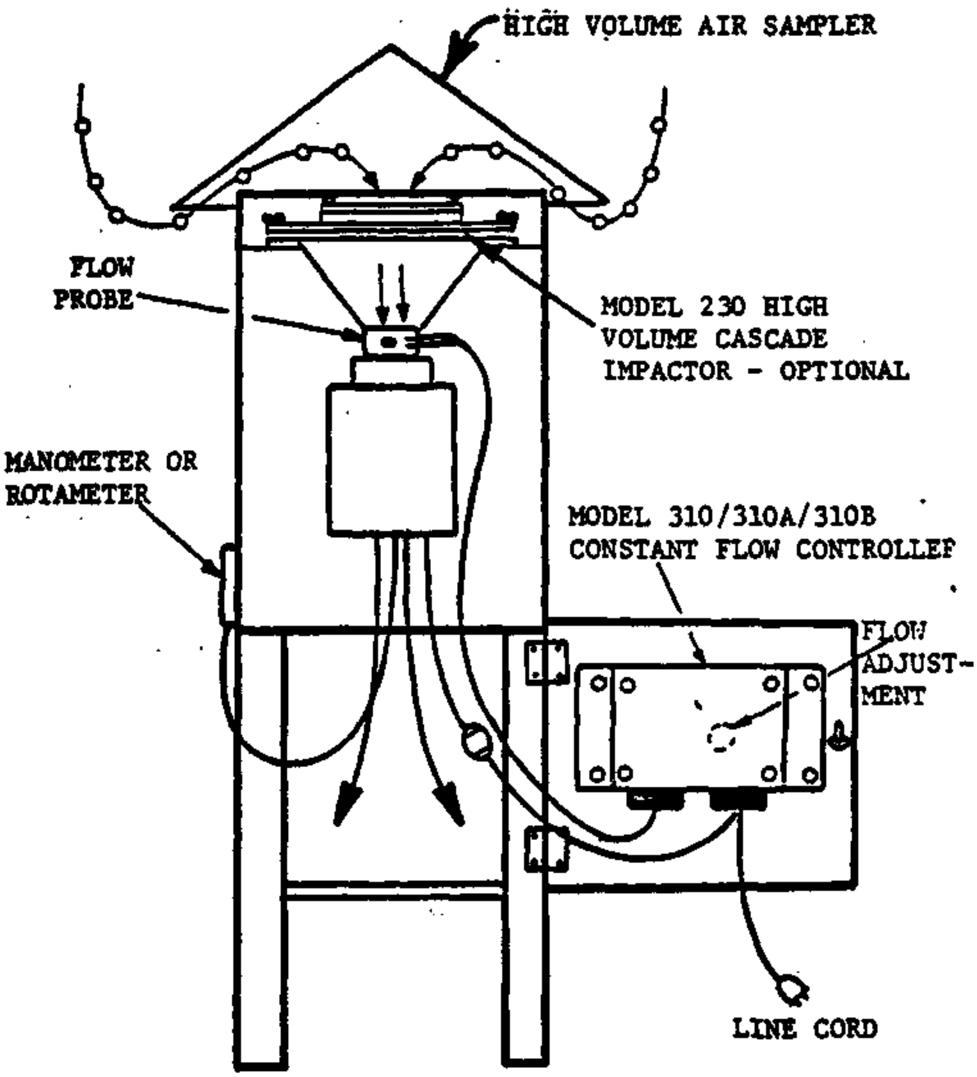


Figure 5-4. Ambient air sampler

5.7 Sample Recovery

Upon completion of the ESP and stack sampling, the sampling equipment was brought to the laboratory area for recovery. Each sample train was kept in a separate area to prevent sample mixup and cross contamination.

The dry powder in the cyclone, probe, and heated flexline was collected in the cyclone catch bottle. After this collection procedure, the individual sample train components were recovered per the following:

- Probe was wiped to remove all external particulate matter near probe ends.
- Filters were removed from their housings and placed in proper container.
- After recovering dry particulate from the nozzle, probe, heated teflon line, cyclone, and flask, these parts were rinsed with distilled water to remove remaining particulate. They were subsequently rinsed with B & J acetone and cyclohexane and put into a separate container. All rinses were retained in an amber glass container.
- Sorbent traps were removed from the train, capped with glass plugs, and given to an on-site Midwest Research Institute (MRI) representative.
- Condensing coil, if separate from the sorbent trap, and the connecting glassware to the first impinger was rinsed into the condensate catch (first impinger).
- First and second impingers were measured, volume recorded and retained in an amber glass storage bottle. The impingers were then rinsed with small amounts of distilled water, acetone and cyclohexane. These rinsings were combined with the condensate catch. Rinse volumes were also recorded .
- Third and fourth impingers were measured, volume recorded and solutions discarded.
- Silica gel was weighed, weight gain recorded and regenerated for further use.

To preserve sample integrity, all glass containers were amber glass, with Teflon-lined lids.

5.8 Problems Encountered During Recovery

- If the temperature of the probe, flexline, or oven box was not sufficient ($\nless$ 250°F) to prevent moisture from condensing, the particulate would cake on the inner walls and become very difficult to remove.

- Due to the cyclohexane not readily evaporating and adhering to the inner walls, the flex lines and probe liners gave the appearance of being clean when in reality they were still wet and masked any particulate that remained on the walls. Therefore, all components must be thoroughly dry before a visual inspection can be made. If the initial rinses do not remove all the particulate, then brushing with additional water rinses is required to clean the walls. This is then followed with acetone and cyclohexane rinses.

6.0 CALIBRATION

This section describes the calibration procedures used prior to conducting the field test at Ames Municipal Power. Figure 6-1 shows the calibration equipment and how it was set up.

6.1 Method Five Calibration Data

6.1.1 Orifice meter calibration. The orifice meter calibration is performed using a pump and metering system as illustrated in Figure 6-1(a). The dry gas meter with attached critical orifice is run at various orifice flows for a known time. After each run the volume of the dry gas meter, meter inlet/outlet temperatures, time, and orifice setting is recorded. The orifice meter calibration factor is derived by solving the equation.

$$\Delta H@ = \frac{0.317\ \Delta H}{Pb\ (T_d + 460)} \left[\frac{(Tw + 460)\ \Theta}{Vw}\right]^2$$

where

ΔH = Average pressure drop across the orifice meter, inches H_2O

Pb = Barometric pressure, inches Mercury

T_d = Temperature of the dry gas meter, °F

Tw = Temperature of the wet test meter, °F

Θ = Times, minutes

Vw = Volume of wet test meter, cubic feet

The $\Delta H@$ yielded is utilized to adjust the sampling train flow rate by regulating the orifice flow.

6.1.2 Dry gas meter calibration. Meter box calibration consists of checking the dry gas meter for accuracy. The dry gas meter with attached critical orifice is connected to a wet test meter (see Figure 6-1(b) below) and run at various orifice flows for a known time. After each run wet and dry gas meter volumes, temperatures, time, and orifice readings are recorded.

Utilizing the equation

$$V = \frac{Vw\ Pb\ (Td+460)}{Vd\ \left(Pb+\frac{\Delta H}{13.6}\right)(T_w + 460)}$$

where

V = Volume correction factor

V_w = Volume of wet test meter, cubic feet

P_b = Barometric pressure, inches Mercury

T_d = Temperature dry gas meter, °F

V_d = Volume of dry gas meter, cubic feet

ΔH = Average pressure drop across the orifice meter, inches H_2O

T_w = Temperature of wet test meter, °F

a volume factor which compares the dry gas meter with the wet test meter is obtained.

6.1.3 Pitot tube calibration. Pitot tubes are calibrated on a routine basis utilizing two methods.

The type S pitot tube specifications are illustrated and outlined in the Federal Register, Standards of Performance for New Stationary Sources, [40 CFR Part 60], Reference Method 2 (refer to Figure 6-1(c)). When measurment of pitot openings and alignment verify proper configuration, a coefficient value of 0.84 is assigned to the pitot tube.

If the measurements do not meet the requirements as outlined in the Federal Register, a calibration is then performed by comparing the S type pitot tube with a standard pitot tube (known coefficient of 1.0). Under identical conditions, values of ΔP, for both S type and standard pitot tube are recorded using various velocity flows (14 fps to 60 fps). The pitot tube calibration coefficient is determined utilizing the following equation,

$$\text{Pitot Tube Calibration Factor (CP)} = \left(\text{Standard Pitot Tube Coefficient}\right) \times \left[\frac{\Delta P \text{ reading of std. pitot}}{\Delta P \text{ reading of S type pitot}}\right]^{1/2}$$

The coefficient assigned to the pitot tube is the average of calculated values over the various velocity ranges.

6.1.4 Nozzle diameters. The nozzle diameters were calibrated with the use of a vernier caliper if the nozzle showed excessive wear or was considered not fit for use, it was discarded.

6.2 Instrument Calibration

Manufacturers recommended calibration procedures were used with the following gases which had an analytical accuracy of $\pm$ 1%:

SCOTT CO 812 ppm
CO_2 11.94%
O_2 4.98%
Propane 34.4 ppm
in Nitrogen Balance

Zero and Calibration adjustment were made prior to the start of the test day. Zero drift checks were made at the end of each test period. Data was recorded every fifteen minutes thus providing two data points per hour for each sampling position.

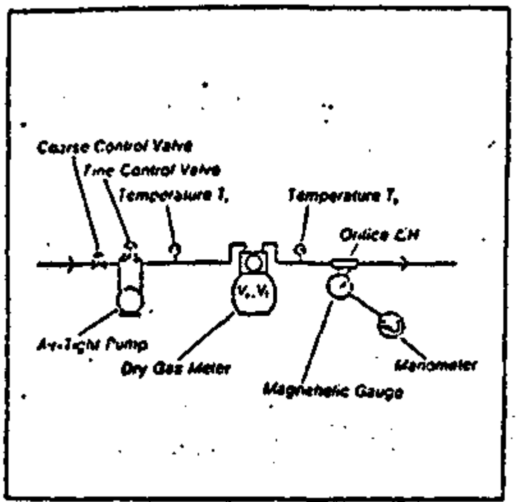


Figure 6-1(a)
Orifice meter calibration

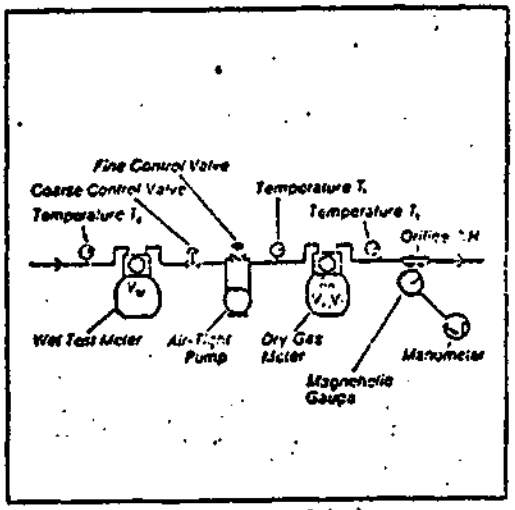


Figure 6-1(b)
Dry gas meter calibration

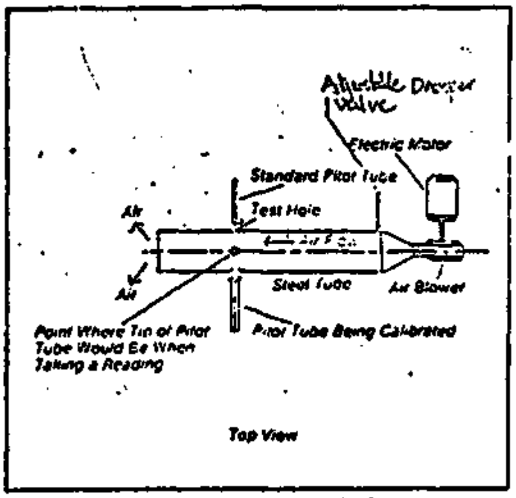


Figure 6-1(c)
Equipment used to calibrate pitot tubes

Figure 6-1. Calibration equipment set-up procedures

7.0 TECHNICAL PROBLEMS AND RECOMMENDATIONS

This section describes some of the problems encountered during the Ames test program and recommends a solution to these problems.

7.1 Problems

- Construction of weather shelters was not completed on schedule causing a one day delay.
- Because of extreme cold weather additional heaters had to be supplied to both the stack and monitoring truck. This resulted in additional power requirements and caused approximately a half day down time for installation of power switches.
- Cold weather also effected the following:

  1) heat lines did not maintain temperature causing moisture to condense and possibly act as a scrubber for hydrocarbons. Therefore, hydrocarbon data are considered only fair.
  2) The gas conditioner would freeze restricting sample gas flow to the monitoring equipment. This created data gaps during the test period.
  3) Solutions in the sampling trains would freeze causing the test to be shortened or scrubbed.
  4) Cyclohexane would freeze at the temperatures encountered at the sampling locations because it has a freezing point higher than water.

- Three instruments malfunctioned due to electronics failure or change. These instruments were:

  1) Infrared Industries CO/CO_2 analyzer. The CO section would not maintain calibration and was removed from the system. It was replaced with the Beckman CO analyzer.
  2) Beckman O_2 analyzer. Detector malfunctioned and was replaced with backup O_2 analyzer.
  3) Beckman CO Analyzer. Energy source went out of adjustment and could not maintain calibration. No other replacement was available, as a result, 2 days of CO data were not recorded.

7.2 Recommendations

The only significant problems that occurred at the Ames facility were caused by severe weather conditions. In the future, the testing should preferably take place in a warmer environment, during the warmer time of the year or heated constant temperature shelters should be provided.

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-2-80

*Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A
MW Gross Net									25 23.1	26 24	28 26.1	29 26.6
Steam flow rate 1000's lbs/hr	235	215	210	200	222	208	208	195	220	240	250	260
Steam pressure psig	855	850	850	855	850	855	860	855	860	860	860	860
Steam temperature °F	900	895	895	900	880	890	895	895	910	910	900	890
Feedwater flow rate 1000's lbs/hr	250	232	228	205	225	220	220	205	230	240	250	270
Feedwater temp °F									350	360	360	370
Fuel feed rate (coal) 1000's lbs/hr fuel gauge readings gals/hr fuel oil	19.6 37831.4 76454.1 5780.7	32	28.5	27.5	28	27.5	27.5	26	27	29	33.5	33
RDF	←		No RDF									
Excess air %	18	20	22	22	25	21	21	20	22.5	20	21	22
I.D. Fans amps	45	45	45	46	46	45	45	46	45	45	46	47
I.D. Fans pressure psig	5.0	3.9	5.0	4.0	3.5	4.5	4.5	4.5	5.0	4.0	6.0	4.5
FD Fans amps	29	30	30	29	30	29	29	29	30	30	30	30
FD Fans pressure	3.4	4.0	4.2	3.5	4.5	3.5	4.0	3.5	4.0	3.0	5.0	4.0
Furnace draft psig	0.3	0.4	0.4	0.3	0.15	0.8	0.65	0.84	0.7	0.7	0.6	0.8
Flue gas boiler exit Temp °F ESP inlet									635 300	640 320	640 320	640 320
Ambient temp °F	8	8	8	8	7	7	7	5	9	12	18	19
Ambient pressure inches Hg	29.54	29.52	29.51	29.87	29.47	29.46	29.44	29.41	29.4	29.39	29.38	29.38

Time	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross Net	30 27.6	30 27.6	29.5 27.1	29.5 27.2	29 26.6	29 26.6	32	35	34	34	33	30	30.19* 26.25*	2.8* 1.51*
Steam flow rate 1000's lbs/hr	265	270	275	260	260	260	280	310	310	310	312	270	252.2	36.49
Steam pressure psig	860	860	850	860	860	860	860	860	865	860	860	860	857.7	4.16
Steam temperature °F	910	905	910	910	910	905	900	900	900	900	882	899	899.63	8.53
Feedwater flow rate 1000's lbs/hr	275	280	270	265	265	275	290	320	322	330	320	289	261.17	37.94
Feedwater temp °F	370	370	375	365	370	370							366*	7.30*
Fuel feed rate (coal) 1000's lbs/hr fuel gauge readings gals/hr fuel oil	34	34	32	33	33	33.5	36	38.5	38.6	38.8	37.5	33.6 Coal Oil	31.7 32.2 4.6	7.07
RDF												→		
Excess air %	22	24	24	22.5	22	21	23	20	19	24	23	21	22	2.1
I.D. Fans amps	47	47	47	47	47	47	47	48	48	48	48	47	46.42	1.1
I.D. Fans pressure psig	5.5	6.0	5.0	5.5	5.0	5.0	5.5	6.5	6.3	7.0	6.0	5.0	5.15	0.89
FD Fans amps	30	30	30	30	30	30	32	32	32	33	32	31	30.29	1.12
FD Fans pressure	4.5	4.5	3.0	4.0	4.5	4.5	5.0	5.2	5.1	6.2	5.2	3.9	4.26	0.77
Furnace draft psig	0.5	0.7	0.8	0.6	0.6	0.7	0.90	0.7	0.6	0.5	0.55	0.7	0.60	0.20
Flue gas boiler exit Temp °F ESP inlet	645 320	660 320	660 320	660 320	640 325	650 320							647* 318.5*	9.70* 6.69*
Ambient temp °F	22	23.5	26	26	27	26	23	22	19	19	18	18	16.86	7.58
Ambient pressure inches Hg	29.36	29.31	29.25	29.24	29.2	29.19	29.15	29.14	29.15	29.13	29.12	29.11	29.34	0.10

Comments

Bottom Ash Removal and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.30A, 6.00A, 9.48A, 2.12P, 6.05P, 10.15P

Soot Blown
Start - 1.00A, 10A, 8.15P

RDF Density
No RDF Fired

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-3-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	29	12	18	18	18.5	18.5	27	29	34.75	35	35	34.25	34.5	36	36	35	34.6	34.5	35	35	35	36	34	31	30.1	7.31
Net									32.35	32.5	32.4	31.66	32.0	32.5	32.4	32.6	32.0	32.8	32.5	32.6	32.6	32.6	31.5	28.6	32.04*	0.98*
Steam flow rate 1000's lbs/hr	240	95	150	155	155	155	240	265	320	330	315	315	316	310	313	320	318	310	315	316	315	315	300	271	268.8	71.48
Steam pressure psig	860	850	850	850	850	860	860	850	850	855	855	860	856	850	850	850	845	850	850	855	850	865	865	850	852.71	4.66
Steam temperature °F	895	820	820	900	895	890	885	900	900	910	900	910	900	900	900	910	918	900	900	900	890	882	880	865	890.1	24.01
Feedwater flow rate 1000's lbs/hr	255	100	165	160	160	160	248	270	335	330	330	325	320	320	310	320	315	320	320	325	326	325	328	314	278.38	71.65
Feedwater temp °F									380	380	380	380	380	380	385	385	385	380	380	380	380	380	380	378	380.81	2.14
Fuel feed rate (coal)	30.5	10.5	21.6	21.1	21.5	21.6	32.7	33.0	39	39	38.5	40	36	36.5	34.0	33.8	35.0	35.0	36.1	36.9	34.7	34.5	33.6	32.8	31.93	7.32
1000's lbs/hr	38215.9																							Coal	31.69	
Fuel gauge reading	76842.3																							Oil	4.6	
RDF	5786.8	← No RDF →											System A started 10.53A System B started 11.10P				System B down 3.24P System B on 3.47P									
Excess air %	21	39	33	36	36	38	18	18	19	24	22	18	17.5	20	17.5	20	27	15	15	10	14	16	20	16	22.08	8.28
I.D. fans amps	46	39	43	43	43	43	46	47	48	48	47	47	47	47	47	48	48	46	46	46	46	46	46	45	45.75	2.15
I.D. fans pressure psig	5.5	2.6	3.8	3.6	3.6	3.6	5.0	5.0	6.7	7.0	6.5	7.0	6.5	7.0	7.8	7.0	7.0	6.0	6.0	6.2	6.4	6.3	6.5	5.9	5.67	1.40
F.D. fans amps	31	26	27	27	27	27	30	30	32	32	31	32	30	30	30	31	32	30	31	30	31	31	30	30	29.91	1.79
F.D. fans pressure	4	1.8	2.1	2.2	2.5	2.5	4.8	4.5	5.5	5.5	5.0	4.5	4.0	4.0	4.0	5.0	5.5	3.0	4.7	4.5	4.6	4.7	3.7	2.8	3.94	1.13
Furnace draft psig	0.7	0.6	0.61	0.55	0.6	0.6	0.9	0.51	0.5	0.55	0.4	0.7	0.6	0.65	0.3	0.5	0.65	0.6	0.5	0.65	0.7	0.56	0.5	0.7	0.59	0.10
Flue gas temperature °F									700	700	710	660	660	680	680	690	700	700							688*	17.51*
Ambient temperature °F	17	17	17	18	18	18	19	19	20	24	31	36	37	38	39	41	42	42							27.39*	10.39*
Ambient pressure inches Hg	29.09	29.05	29.01	29.00	28.98	28.95	28.93	28.91	28.91	28.86	28.85	28.83	28.8	28.8	28.76	28.75	28.75	28.76							28.89*	0.11*

Comments

Bottom Ash Removal and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.25A, 6.06A, 10.00A, 2.45P, 6.05P, 10.40P

Soot Blown
Start - 12.30A, 10.05A, 9.55P

RDF Density - 5 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-4-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	27	23	23	23	23	23	26	30	35.5	35.5	35.5	35.0	35.5	35.0	35.5	35	35.5	35.0	35.0	35.0	35.0	35.0	35.0	32	33.58	5.19
MW Net	25	21.2	21.1	21.1	21.2	21.2	24.1	26.7	33	33	33	32.5	33.0	32.5	32.9	32.5	33.0	32.56	32.6	32.6	32.6	32.6	32.5	29.7	29.25	4.93
Steam flow rate 1000's lbs/hr	236	190	190	190	190	190	235	272	325	320	325	320	325	320	325	325	330	325	325	325	330	325	320	280	284.07	56.59
Steam pressure psig	850	840	840	850	845	855	845	845	860	850	855	845	855	850	850	845	855	850	850	850	855	855	856	865	850.63	5.96
Steam temperature °F	880	885	888	885	865	880	885	900	910	900	905	900	900	900	905	880	905	900	895	895	945	890	900	885	891.46	14.63
Feedwater flow rate 1000's lbs/hr	250	202	201	201	206	206	230	200	330	305	325	340	325	325	330	330	325	315	330	330	340	332	330	285	290.79	52.98
Feedwater temp °F									380	380	385	390	390	380	390	385	390	395	400	400	400	400	390	380	389.7	7.63
Fuel feed rate (coal) 1000's lbs/hr fuel gauge readings gallons/hr fuel oil RDF	26.6 38590.7 77228.1 5787.9 On	22.6	23.0	22.0	21.8	20.2	27.5	33.5	34.5	36.0	34.0	34.0	34.0	34.0	34.5	34.5	33.0	34.0	35.2	34.6	34.3	35.3	35.8	30.5 Coal Oil	31.03 31.01 2.9	5.37
Excess air %	19	25	22	20	26	22	20	15	20	18	23	22	19	20	18	18	20	23	19	19	19	20	19	20	20.33	2.35
I.D. fans amps	45	43	43	43	43	43	45	46	47	47	48	47	47	47	47	47	47	47	47	48	47	48	47	46	46.04	1.76
I.D. fans pressure psig	4.9	4.0	4.1	3.5	5.1	5.5	5.0	5.6	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.5	7.1	7.1	6.7	6.9	6.5	6.5	6.17	1.14
FD fans amps	29	28	28	27	27	27	28	28	30	30	30	30	30	30	30	30	31	31	31	31	31	31	31	30	29.54	1.41
FD fans pressure psig	4.0	3.6	3.5	3.1	2.5	3.0	3.9	5.0	5.5	5.0	4.0	4.5	4.5	4.5	4.5	5.0	4.5	5.0	4.8	4.9	4.8	5.3	4.7	3.5	4.32	0.78
Furnace draft psig	0.5	0.4	0.2	0.3	0.8	0.9	0.6	0.5	0.5	0.6	0.7	0.65	0.5	0.6	0.6	0.5	0.6	0.6	0.7	0.6	0.72	0.60	0.67	0.7	0.585	0.15
Flue gas temp Boiler °F									690	680	700	670	680	680	690	690	695	695							687*	9.19*
Flue gas temp ESP inlet °F									350	340	340	340	340	340	340	340	340	340							341*	3.16*
Ambient temperature °F	32	31	30	30	30	29	28	28	28	27	27	26	26	26	26	26	25	22	18	17	15	12	10	9	24.08	6.81
Ambient pressure inches Hg									28.84	28.84	28.85	28.86	28.86	28.83	28.83	28.81	28.82	28.83	28.89	28.91	28.94	28.96	28.98	28.99	28.88*	0.06*

Comments

Bottom Ash and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.05A, 6.10A, 10.00A, 2.10P, 6.00P, 10.25P

Soot Blown
Start - 4.0A, 10.02A, 7.30P

RDF density - 4 lbs/cu ft, 5 lbs/cu ft, 5 lbs/cu ft[1]

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-5-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	29	26.5	26	22	21.5	22	30	32	35	35	35	35	35	35	34.5	36	35	36	36	35	35	36	35	32	31.9	4.76
MW Net	26.8	24.6	23.9	20	19.5	22.1	28	29.7	32.6	32.7	32.5	32.6	32.7	32.7	32.8	32.9	32.7	32.7	32.6	32.7	32.5	32.6	32.7	29.7	29.72	4.44
Steam flow rate 1000's lbs/hr	250	245	225	185	185	188	280	295	320	315	320	315	315	320	315	326	325	320	320	320	322	325	320	300	289.58	40.47
Steam pressure psig	855	840	850	840	850	850	850	845	850	850	850	850	845	850	845	855	856	850	850	855	850	850	850	830	848.54	5.61
Steam temperature °F	890	890	890	885	870	900	895	900	910	910	905	900	890	900	906	910	905	910	895	895	885	885	900	880	895.6	10.97
Feedwater flow rate 1000's lbs/hr	265	245	250	200	205	200	290	298	330	338	330	340	330	315	325	330	338	325	330	330	340	335	330	307	300.42	46.6
Feedwater temp °F	390	365	360	348	345	346	380	380	400	400	395	395	390	395	395	395	395	395	390	398	390	385	390	375	382.8	17.36
Fuel feed rate (coal) 1000's lbs/hr Fuel gauge readings (gallons/hr) fuel oil RDF	29.6 38982.6 77599.7 6788.6	28.9	22.5	19.1	23.4	19.5 5.20A →	36.1	37.4	41 No RDF	40.5	40.5	37 → 10.20A RDF Restarted	37.8	34	35	33	32	33	33.6	33.9	32.6	33.2	33.2	32.0 Coal Oil	32.45 33.53 2.5	6.09
Excess air %	20	20	20	30	28	31	20	16	17	16	18	19	19	21	19	18	18	20	19	19	18	18	19	21	20.17	3.92
ID fans amps	46	46	45	45	45	44	48	48	48	48	47	48	47	47	47	47	47	47	47	47	48	47	47	46	46.75	1.11
ID fans press psig	6.5	5.5	4.9	4.8	3.2	6.0	6.0	4.5	6.0	6.5	6.5	7	6.7	6.5	6.5	7.0	6.5	7.0	6.5	6.8	7.5	6.5	6.0	7.0	6.09	1.04
FD fans amps	29	30	28	28	28	28	32	31	32	32	31	32	31	31	31	30	30	30	31	31	32	31	31	31	30.46	1.35
FD fans press psig	4.0	5.9	1.0	2.6	2.9	4.0	5.1	5.5	5.0	5.0	5.0	5.5	4.2	4.0	4.0	4.0	4.0	3.75	4.7	4.6	5.3	4.5	4.3	4.9	4.32	1.06
Furnace draft psig	0.5	0.7	0.8	0.3	0.8	1.0	0.7	0.45	0.6	0.6	0.65	0.65	0.8	0.7	0.4	0.45	0.6	0.7	0.6	0.7	0.5	0.6	0.45	0.6	0.67	0.154
Flue gas temperature Boiler exit									695	700	700	680	690	690	695	700	700	700							695*	6.67*
Flue gas temperature ESP inlet									345	345	345	345	345	345	350	345	345	345							345.5*	1.50*
Ambient temp °F	2	4	4	2	2	2	1	1	1	4	6	7	8	10	12	14	15	15	15	14	13	12	10	9	7.63	5.22
Ambient press inches Hg	29.00	29.03	29.04	29.07	29.08	29.10	29.11	29.13	29.13	29.22	29.24	29.24	29.24	29.24	29.24	29.22	29.23	29.22	29.22	29.22	29.23	29.23	29.23	29.23	29.17	0.08

Comments

Bottom Ash and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.15A, 6.10A, 10.00A, 2.00P, 6.00P, 9.56P

Soot Blown
Start - , 10A, 7P

RDF density - 5 lbs/cu ft, 5 lbs/cu ft, 5 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-6-88 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A
MW Gross	28	22	22	21.6	21.5	21.5	24.5	33	34.5	33.5	35	35
MW Net	25.7	20.2	20.1	19.7	19.6	19.7	22.5	30.6	32.1	31.1	32.6	32.5
Steam flow rate 1000's lbs/hr	256	185	185	181	180	182	215	285	310	305	325	320
Steam pressure psig	840	850	840	840	830	848	850	858	855	840	855	856
Steam temperature °F	880	880	890	900	890	893	890	900	920	900	900	900
Feedwater flow rate 1000's lbs/hr	279	200	196	198	204	195	230	292	320	315	330	335
Feedwater temp °F	379	338	338	338	336	340	390	380	390	390	390	385
Fuel feed rate (coal)	28.8								36.5	35	36	35.5
1000's lbs/hr	39486.3											
Fuel gauge readings	77988.7											
gallons/hr fuel oil	5789.2											
RDF						5.40A System B off 8.00AM only 1 conveyor 6.00A System B on 9.00AM both conveyors on						
Excess air %	21	36	30	34	34	32	28	15	17	20	21	18
ID fans amps	45	44	44	43	44	44	44	46	47	47	47	47
ID fans press psig	5.5	3.9	5.3	5.6	5.0	5.5	5.0	5.5	6.5	7.0	6.5	7.0
FD fans amps	29	28	28	28	29	28	28	30	30	32	30	32
FD fans press psig	2.4	2.3	3.5	3.7	4.5	2.8	2.0	3.8	5	6	4.5	6.5
Furnace draft psig	0.7	0.45	0.8	0.9	0.65	0.8	0.8	0.5	0.7	0.7	0.6	0.6
Flue gas temp °F Boiler exit									680	690	700	680
ESP inlet									340	340	340	340
Ambient temp °F	9	7	6	6	8	10	12	12	13	16	20	22
Ambient press inches Hg	29.22	29.21	29.17	29.14	29.14	29.12	29.11	29.09	29.08	29.06	29.06	29.03

Time	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	35	35	36	35	35	36	35	36	34	35	36	32	31.17	5.55
MW Net	32.6	32.6	32.5	32.6	32.5	32.6	32.5	32.6	31.5	32.6	32.5	29.6	28.88	5.38
Steam flow rate 1000's lbs/hr	320	320	320	315	320	320	320	320	320	320	310	282	279.79	56.73
Steam pressure psig	855	850	845	845	850	850	850	850	855	850	830	835	847.33	7.22
Steam temperature °F	900	900	890	910	905	906	890	895	885	885	900	880	895.33	9.89
Feedwater flow rate 1000's lbs/hr	330	330	330	330	330	325	330	330	340	330	312	290	291.7	54.23
Feedwater temp °F	390	395	390	390	390	390	385	385	390	390	390	380	377.46	21.03
Fuel feed rate (coal)	33	36.5	34	38	36	36	36.4	35.6	36.5	36.3	34.0	31.8	35.38*	1.53*
												Coal	32.15	
												Oil	3.75	
Excess air %	20	16	19	21	18	20	18	19	20	18	19	19	22.21	6.30
ID fans amps	47	47	47	47	48	47	48	47	48	48	46	46	46.17	1.55
ID fans press psig	6.5	7	7	7	6	4.5	6.4	6.9	6.8	6.5	6.8	6.1	6.08	0.89
FD fans amps	30	31	31	31	31	32	31	32	32	32	31	31	30.29	1.49
FD fans press psig	4	5	4.5	5	5	7	5	5	5.4	4.9	5.1	4.8	4.49	1.25
Furnace draft psig	0.45	0.45	0.45	0.6	0.4	0.7	0.5	0.51	0.61	0.60	0.62	0.60	0.61	0.13
Flue gas temp °F Boiler exit	680	690	690	690	690	690							688*	6.32*
ESP inlet	340	340	340	340	340	340							340	0
Ambient temp °F	25	26	26	29	32	32	30	30	28	27	25	24	19.79	9.19
Ambient press inches Hg	28.98	28.96	28.94	28.93	28.93	28.93	28.95	28.95	28.97	28.97	28.97	28.97	29.04	0.096

Comments

Bottom Ash and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.35A, 6.30A, 10.12A, 2.06P, 6.15P, 11.23P

At 10.10A ESP hoppers down for repairs

Soot Blows
Start - 3.15A, 10.02A, 7.13P

RDF density - 5.0 lbs/cu ft, 4.0 lbs/cu ft, 4 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-7-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	20	20	20.5	21	15	15	26	30	36	36	36	36	35.5	36	36	36	35	35.5	35	35	36	35	35	32	30.5	7.61
MW Net	18.2	18.2	16.6	19.2	13.2	13.3	24	27.7	33.5	33.5	33.5	33.6	33.0	33.6	33.4	33.4	32.6	33.1	32.5	32.5	32.5	32.6	32.5	29.6	28.24	7.21
Stem flow rate 1000's lbs/hr	170	169	170	177	120	128	210	280	325	330	330	325	330	326	325	325	328	325	325	327	325	320	318	288	274.8	74.9
Steam pressure psig	845	845	850	840	840	850	850	855	855	855	860	855	855	855	856	850	850	850	840	850	850	850	855	850	850.21	5.21
Steam temperature °F	878	890	895	905	843	885	885	900	900	910	912	905	870	895	900	905	900	900	885	890	875	880	895	900	891.8	15.19
Feedwater flow rate 1000's lbs/hr	178	175	175	185	145	135	225	280	335	340	340	340	340	345	340	340	350	338	340	335	345	336	322	288	286.33	76.82
Feedwater temp °F	340	340	340	340	320	315	355	378	400	400	390	395	395	395	395	390	390	395	385	385	382	385	385	375	373.75	26.6
Fuel feed rate (coal) 1000's lbs/hr	19.0	20	20	25.5	17.6	18.0	32.5	35.0	42	42.5	42.5	41.5	41.5	37	36	35.5	35.5	35	25.3	25.7	31.6	34.9	33.6	31.2	31.65	8.23
	39801.5																							Coal	33.6	
Fuel gauge readings gallons/hr fuel oil	78357.1																							Oil	4.2	
	5790.1																									
RDF				3.20A ←					No RDF				→ 12.30P RDF Restarted													
Excess air %	40	37	47	37	50	50	21	16	20	21	19	18	20	20	20	20	16	20	19	19	19	19	19	19	25.25	11.2
ID fans amps	43	42	43	44	42	42	46	47	49	49	48	48	48	48	48	48	48	48	48	48	48	48	47	45	46.46	2.41
ID fans press psig	3.8	3.8	5.2	5.5	3.5	3.5	3.6	5.4	7.0	6.5	7.0	7.0	7	7	7	7.5	7	7	7.2	7.0	7.2	7.1	6.6	6.0	6.06	1.4
FD fans amps	28	28	28	28	27	28	30	31	32	32	32	32	32	32	32	32	32	31	32	32	32	32	31	30	30.67	1.79
FD fans press psig	2.0	2.0	2.5	4.6	2.2	2.0	3.8	5.4	6	6	6	6	6	5	5	5	5	5	5.4	5.3	5.6	5.1	4.2	3.8	4.54	1.41
Furnace draft psig	0.55	0.6	0.8	0.85	0.6	0.6	0.25	0.55	0.6	0.7	0.7	0.6	0.6	0.7	0.7	0.8	0.6	0.65	0.71	0.64	0.51	0.70	0.53	0.66	0.63	0.12
Flue gas temp °F																										
Boiler exit									700	705	700	705	695	695	695	695	700	700							699*	3.94*
ESP inlet									350	350	340	340	340	340	340	340	340	340							342*	4.22*
Ambient temp °F	21	21	19	19	19	20	20	20	20	21	22	26	26	28	28	28	28	30	30	30	29	29	28	28	24.58	4.29
Ambient press inches Hg	29.02	29.02	29.02	29.02	29.03	29.02	29.01	29.00	29.00	28.99	28.99	29.00	28.99	28.97	28.95	28.91	28.92	28.92	28.92	28.92	28.92	28.91	28.88	28.92	28.97	0.048

Comments

Bottom Ash and Fly Ash Removal
Start - 1.30A, 5.30A, 9.30A, 1.30P, 5.30P, 9.30P
Finish - 2.10A, 6.00A, 10.00A, 1.55P, 6.00P, 10.17P

Soot Blown
Start - 3.20A, 11.32A, 7.20P

RDF density per shift - 4 lbs/cu ft, 4 lbs/cu ft - 4 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-8-80

*Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	30.5	20	20	20	23	15	15	23.5	27	29.6	31.5	32.5	31.5	30.6	29.5	28	31	32	32.5	35	36	33	32	31	27.85	6.01
MW Net	28.2	18.2	18.2	18.2	21.2	13.1	13.1	21.7	25	27.1	29.2	30.1	29.2	28.0	27.2	25.7	28.7	29.5	30.2	32.6	32.6	30.6	29.7	28.6	25.66	5.79
Steam flow rate 1000's lbs/hr	265	170	165	165	196	125	125	124	235	260	275	285	280	275	250	240	265	280	290	315	317	303	278	262	239.33	61.67
Steam pressure psig	850	850	845	850	850	850	850	850	850	835	855	855	855	850	850	845	850	850	850	850	860	855	850	870	851.06	6.08
Steam temperature °F	895	900	882	900	900	868	880	890	900	900	906	910	870	885	895	900	910	900	895	895	900	878	885	905	893	12.93
Feedwater flow rate 1000's lbs/hr	275	190	175	175	203	135	134	130	245	270	280	290	295	290	270	255	280	295	300	320	335	318	285	280	251.4	62.96
Feedwater temp °F	375	340	330	325	345	310	305	305	360	370	370	370	370	370	370	380	375	380	385	385	385	380	380	370	360.2	25.81
Fuel feed rate (coal) 1000's lbs/hr fuel gauge readings gallons/hr fuel oil	30.5 40212.5 78752.0 5791.1								32.5	34.0	33.0	33.5	31.0	31.5	31.5	30.5	31.5	31.0	31.6	33.4	33.2	33.5	31.3	31.0 Coal Oil	32.03* 28.17 5.4	1.17*
RDF					←—No RDF 4 AM onwards					——→ 9 AM RDF on																
Excess air %	17	39	30	30	33	50	50	50	21	20	20	19	19	20	21.5	21	19	18	19	19	19	19	19	19	25.40	10.9
ID fans amps	45	44	42	43	44	42	42	42	47	47	47	47	46	46	46	45	46	45	46	46	47	45	45	45	45	1.72
ID fans press psig	5.6	3.5	3.8	4.0	4.2	3.5	3.5	3.5	6	6	6	6.5	5.5	6	5	5	5.5	6	5.8	6.5	6.7	5.8	6.0	5.2	5.21	1.07
FD fans amps	30	28	28	28	28	28	28	28	30	30	30	30	30	30	30	29.5	30	30	30	30	31	30	30	30	29.44	0.97
FD fans press psig	3.5	2.0	2.9	2.5	3.0	2.0	2.0	1.9	4.5	4.5	4	5	4	3	3	3	4.5	5	5.0	4.3	4.5	4.2	3.7	3.0	3.54	1.03
Furnace draft psig	0.56	0.3	0.5	0.35	0.32	0.6	0.65	0.64	0.6	0.5	0.6	0.5	0.35	0.6	0.65	0.5	0.6	0.5	0.51	0.5	0.55	0.5	0.62	0.61	0.53	0.10
Flue gas temp °F Boiler exit									640	660	660	670	670	660	660	660	660	680							662*	10.33*
ESP inlet									320	330	330	330	340	320	320	320	320	340							327*	8.23*
Ambient temp °F	27	26	26	26	24	24	21	21	20	21	24	26	28	29	31	34	34	36	35	34	33	33	32	32	28.17	4.99
Ambient press Inches Hg	28.92	28.92	28.92	28.93	28.93	28.94	28.97	28.96	28.98	29.03	29.04	29.06	29.06	29.04	29.06	29.05	29.07	29.05	29.07	29.07	29.05	29.05	29.07	29.05	29.01	0.06

Comments

Bottom Ash and Fly Ash Removal
Start - 12.30A, 4.30A, 8.30A, 12.30P, 4.30P, 8.30P
Finish - 12.55A, 5.10A, 9.00A, 1.00P, 5.00P, 9.50P

Soot Blown
Start - 5.20A, 11.30A, 8P

RDF density per shift - 4 lbs/cu ft, 3 lbs/cu ft, 4 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-9-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	28.8	26.5	26.0	25.0	25.0	15.0	15.0	15.0	15.0	25.0	25.0	26.0	26.5	27.0	26.5	25.5	16.5	16.0	16.8	16.8	16.0	16.0	16.0	16.0	20.9	5.31
MW Net	25.6	24.2	24.0	23.1	23.1	13.1	13.2	13.3	13.2	23.0	23.1	24.8	24.3	24.7	24.3	23.4	14.5	15.0	14.2	14.2	14.2	14.2	14.2	14.2	18.9	5.12
Steam flow rate 1000's lbs/hr	247	225	220	215	212	170	122	121	130	212	210	225	230	230	225	220	135	130	131	131	131	135	135	135	178	46.7
Steam pressure psig	840	850	860	885	890	855	870	865	845	850	850	850	845	850	850	850	845	850	845	845	860	850	850	850	854	12.3
Steam temperature °F	880	895	900	880	885	835	880	890	900	895	900	905	860	895	900	900	900	900	885	890	895	875	885	885	888	15.5
Feedwater flow rate 1000's lbs/hr	260	240	235	228	225	205	125	130	130	220	230	235	240	245	235	230	140	140	142	142	142	146	142	144	181	59.3
Feedwater temp °F	375	360	360	353	350	335	300	300	318	360	360	360	355	360	370	360	320	325	320	320	320	320	310	315	338	24.0
Fuel feed rate (coal) 1000's lbs/hr	33.5	29.5	29.2	24.0	27.5	25.0	19.1	18.3	17.5	31.0	31.5	31.0	30.7	32.0	30.5	30.6	19.5	19.0	19.3	19.3	19.0	19.8	20.0	19.3	24.8	5.75
Fuel gauge readings Fuel oil	405 598 790 815 579 248																							Coal Oil	23.7 6.25	NA NA
RDF					4.45A →								No RDF →													
Excess air %	20	17	20	25	27	40	>50	>50	>50	26	20	22	28	20	22	22	47	47	46	46	46	43	45	45	34	12.6
ID fans amps	45	44	44	44	44	42	42	42	43	46	46	46	46	46	45	44	42	42	42	42	42	42	42	42	44	1.6
ID fans pressure psig	5.1	5.2	5.2	4.0	3.8	4.1	3.7	3.5	3.5	5.5	5.0	5.0	5.1	4.5	4.0	5.5	3.5	3.5	3.5	3.6	3.5	3.6	3.6	3.6	4.2	0.76
FD fan amps	30	28	30	28	28	28	28	28	28	30	30	30	30	30	30	30	25	27	27	27	27	27	27	27	28	1.5
FD fan pressure	4.2	2.8	5.0	2.7	3.2	3.7	2.3	2.2	5.0	4.0	3.5	4.0	4.9	3.0	3.0	4.0	2.0	2.0	2.0	2.1	2.0	2.0	2.1	2.2	3.1	1.05
Furnace draft psig	0.50	0.70	0.70	0.40	0.42	0.65	0.63	0.58	0.70	0.60	0.50	0.60	0.60	0.50	0.40	0.70	0.65	0.65	0.61	0.61	0.60	0.67	0.61	0.62	0.59	0.092
Boiler flue gas temp °F									600	640	640	640	650	640	640	640	600	600							629*	20.2*
ESP inlet temp °F									265	310	320	320	310	320	320	320	280	280							305*	21.1*
Ambient temp °F	31	31	30	28	27	26	26	27	29	30	38	40	43	44	45	45	46	46	46	43	42	40	39	38	37	7.5
Ambient pressure inches Hg	29.07	29.05	29.04	29.02	29.01	29.00	28.96	28.94	28.89	28.88	28.85	28.84	28.83	28.80	28.80	28.79	28.82	28.81	28.82	28.82	28.82	28.82	28.81	28.78	28.89	0.097

Comments

Bottom and Fly Ash Removal
Start 12.30A, 4.30A, 8.30A, 4.30P, 8.30P
Finish 4.52P, 9.00P

Soot Blown
Start 4.30A, 11.30A, 8.03P

RDF density - 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-10-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross Net	16.0 14.0	16.0 14.0	16.0 14.1	15.0 13.0	16.0 14.1	16.0 14.1	16.0 14.2	29.0 26.6	33.5 30.9	35.0 32.3	35.0 32.3	35.0 32.3	35.0 32.4	35.0 32.4	36.0 32.3	35.0 32.3	36.0 32.3	36.0 32.3	35.0 32.3	35.0 32.3	36.0 32.4	36.0 32.2	35.0 32.3	35.0 32.4	29.1 25.7	8.77 8.43
Steam flow rate 1000's lbs/hr	135	135	137	134	134	130	130	250	310	320	310	310	310	310	316	310	300	310	306	305	311	311	307	270	254	80.2
Steam pressure psig	850	850	850	850	850	858	850	860	836	860	860	860	860	865	860	860	845	855	855	858	855	862	845	825	853	9.1
Steam temperature °F	893	880	898	886	885	880	882	900	898	902	906	904	870	885	902	900	898	904	890	900	895	896	900	860	892	11.5
Feedwater flow rate 1000's lbs/hr	144	145	145	134	140	146	140	235	320	320	325	325	330	325	320	320	325	320	320	320	320	325	330	300	266	83.1
Feedwater temp °F	315	315	315	310	310	308	306	340	380	390	390	390	390	390	390	390	398	390	380	380	380	380	380	380	362	34.9
Fuel feed rate (coal) 1000's lbs/hr	19.5	20.0	20.0	19.6	17.0	17.1	16.5	25.7	37.0	38.0	38.0	38.5	36.5	37.0	37.0	36.5	32.0	33.0	31.6	34.1	34.0	33.0	35.0	31.9 Coal Oil	28.0 31.2 4.17	9.03 NA NA
Fuel gauge readings	408 538 793 563																									
Fuel oil	679 390																									
RDF ←								No RDF								→ Start RDF at 3.12P										
Excess air %	44	46	42	46	46	42	43	16	18	16	16	16	16	16	17	14	16	16	17	17	17	17	17	17	24	12.9
ID fans amps	42	42	42	42	42	41	41	46	47	47	48	48	47	47	48	46	46	46	46	47	47	47	47	45	45	2.5
ID fans pressure psig	3.6	3.5	3.5	3.5	3.5	3.5	3.5	5.0	6.0	6.0	6.0	6.0	6.5	6.8	6.0	6.0	6.5	6.5	6.0	6.1	6.2	6.7	7.6	5.9	5.4	1.32
FD fans amps	28	28	28	28	28	27	27	30	30	30	30	30	30	30	30	30	30	30	30	31	31	30	32	30	30	1.3
FD fan pressure psig	2.3	2.5	2.5	2.5	2.3	2.0	2.0	5.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	4.5	4.5	4.0	4.3	4.9	4.5	4.0	5.2	4.2	4.0	1.10
Furnace draft psig	0.60	0.60	0.65	0.63	0.58	0.57	0.60	-0.60	0.65	0.65	0.55	0.60	0.65	0.60	0.60	0.60	0.65	0.60	0.55	0.55	0.61	0.55	0.55	0.65	0.60	0.036
Boiler flue gas temp °F									680	690	690	690	680	680	680	680	690	690							685*	5.3*
ESP inlet temp °F									340	340	340	340	340	340	340	340	340	340							340*	0.0*
Ambient temp °F	35	36	36	36	38	38	38	38	33	26	23	22	21	21	21	22	22	22	22	22	21	20	20	19	27	7.5
Ambient pressure inches Hg	28.74	28.72	28.70	28.69	28.68	28.69	28.69	28.67	28.74	28.79	28.87	28.94	28.97	29.02	28.90	29.02	29.06	29.06	29.11	29.16	29.16	29.17	29.18	29.19	28.91	0.195

Comments

Bottom and Fly Ash Removal
Start - 12.30A, 4.30A, 2.30P, 4.27P, 8.30P
Finish - 12.50A, 6.00A, 4.16P, 5.42P, 10.30P

Soot Blown
Start - 4.10A, 11.30A, 8.00P

RDF density - 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWERPLANT

UNIT NO. 7

Date 3-11-80 *Not based on 24 hr data

Time	12N	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	30.0	22.0	21.0	20.6	20.5	20.6	20.5	30.8	34.0	35.0	35.0	35.0	36.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	36.0	36.0	35.0	31.0	30.8	6.10
Net	27.5	19.8	19.0	18.5	18.5	18.4	18.5	27.5	31.4	32.2	32.4	32.3	32.4	32.3	32.4	32.4	32.6	32.5	32.4	32.4	32.4	32.3	32.4	18.4	28.8	6.20
Steam flow rate 1000's lbs/hr	260	200	170	171	171	170	170	260	305	310	315	320	320	320	315	315	320	320	320	320	325	330	325	290	277	62.8
Steam pressure psig	845	855	850	850	860	840	855	865	850	850	855	855	855	855	855	855	855	855	860	860	860	870	860	860	855	6.24
Steam temperature °F	900	870	880	885	893	880	880	900	910	900	910	906	890	885	906	900	900	895	905	900	900	890	880	880	894	11.2
Feedwater flow rate 1000's lbs/hr	276	230	185	185	185	194	185	272	315	330	325	330	330	338	325	330	330	330	330	330	330	330	325	300	277	78.5
Feedwater temp °F	370	360	330	330	330	330	330	360	380	390	390	390	390	385	390	390	390	390	385	385	385	385	385	380	372	23.6
Fuel feed rate (coal) 1000's lbs/hr	29.1	21.5	18.5	15.6	16.5	18.0	17.0	25.0	34.5	35.0	36.5	35.0	34.0	35.0	34.0	33.0	33.0	32.5	32.8	33.0	33.0	33.0	33.0	30.8	29.1	7.08
Fuel gauge readings	412 375																							Coal	30.3	NA
	797 281																							Oil	11.25	NA
Fuel oil	679 490																									
RDF																										
Excess air %	20	26	30	22	25	35	30	20	19	19	17	16	17	18	20	17	18	17	17	17	18	17	17	17	20	5.1
ID fans amps	46	44	42	44	44	44	33	46	46	48	48	48	48	48	47	47	46	46	47	47	47	47	47	47	46	3.1
ID fans pressure psig	6.0	3.8	4.6	3.5	3.6	5.0	4.7	5.6	6.5	7.0	6.5	7.0	7.0	6.1	7.0	6.5	7.0	7.0	6.6	6.8	7.2	6.8	6.8	5.8	6.0	1.18
FD fan amps	30	28	28	28	28	28	28	30	30	30	30	30	30	31	30	30	30	30	31	31	31	31	31	30	30	1.1
FD fan pressure psig	4.0	2.5	3.0	2.6	2.5	4.1	3.2	4.3	4.5	6.5	6.0	5.5	6.0	4.9	5.5	5.5	5.5	4.5	5.1	5.4	5.5	5.0	4.6	4.0	4.6	1.12
Furnace draft psig	0.60	0.55	0.58	0.54	0.60	0.60	0.57	0.58	0.60	0.60	0.55	0.60	0.55	0.60	0.58	0.55	0.60	0.63	0.58	0.60	0.58	0.60	0.56	0.54	0.58	0.024
Boiler flue gas temp °F				615	620	600	600	660	670	700	700	700	660	680	686	680	690	700							664*	37.3*
ESP inlet temp °F				280	280	280	280	320	340	340	340	340	340	340	340	340	340	340							323*	27.1*
Ambient temp °F	17	17	16	16	15	15	15	15	17	20	24	28	30	32	32	33	33	33	34	33	32	32	32	32	25	7.9
Ambient pressure inches Hg	29.19	29.19	29.19	29.20	29.21	29.21	29.20	29.20	29.17	29.21	29.18	29.15	29.14	29.19	29.11	29.08	29.06	29.06	29.08	29.08	29.08	29.08	27.06	29.06	29.14	0.061

Comments

Bottom and Fly Ash Removal
Start - 12.30A, 4.30A, 8.29A, 12.38P, 4.30P, 8.23P
Finish - 1.10A, 5.30A, 9.15A, 1.39P, 5.15P, 9.55P

Soot Blown
Start - 4.30A, 11.00A, 8.10P, 11.00P

RDF density - 4.0 lbs/cu ft, 4.0 lbs/cu ft, 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-12-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	21.0	21.0	21.8	20.5	21.0	21.0	29.0	32.5	34.5	35.0	36.0	36.0	35.8	35.0	35.5	35.5	35.5	36.0	36.0	35.8	35.8	35.0	35.8	32.0	31.2	6.26
MW Net	19.8	19.0	19.8	18.4	19.0	18.8	26.6	30.0	31.8	32.3	33.3	33.3	32.3	32.2	32.9	32.9	32.9	33.5	33.4	32.4	32.3	32.4	32.4	19.5	27.1	7.99
Steam flow rate 1000's lbs/hr	185	188	180	170	175	175	250	291	310	325	325	325	325	325	325	325	325	330	325	325	320	310	320	280	255	94.0
Steam pressure psig	850	850	850	840	850	850	860	860	850	855	855	855	855	855	856	855	855	855	860	860	860	860	870	850	855	5.8
Steam temperature °F	880	890	880	880	890	880	900	890	885	910	900	910	900	910	900	900	895	900	890	890	870	880	905	890	893	11.0
Feedwater flow rate 1000's lbs/hr	190	190	190	190	190	196	270	290	320	335	335	335	335	325	330	330	335	335	338	335	350	330	328	290	279	80.2
Feedwater temp °F	348	320	328	320	340	340	360	380	380	380	390	390	390	390	390	390	390	390	365	385	385	380	380	380	370	25.2
Fuel feed rate (coal) 1000's lbs/hr	19.8	17.2	20.1	19.3	17.5	19.0	30.0	32.8	35.6	38.0	35.0	35.0	35.5	35.0	35.0	34.5	34.5	33.5	34.0	35.2	36.3	33.5	33.4	32.8 Coal Oil	30.5 31.8 12.80	7.13 NA NA
Fuel gauge readings	416 106 880 755																									
Fuel oil	579 760																									
RDF								7.45A only 1 conveyor 9.00A both conveyors on																		
Excess air %	30	30	30	30	29	27	20	19	19	16	19	15	18	22	15	14	16	14	15	15	16	20	14	24	20	5.9
ID fans amps	44	43	43	43	42	43	45	45	46	47	47	47	48	48	47	46	46	46	47	47	48	46	47	45	46	1.8
ID fans pressure	4.1	4.8	4.6	3.8	5.3	4.0	5.6	6.4	6.0	6.0	7.0	7.0	7.5	8.0	7.0	7.0	7.0	7.0	6.8	6.8	7.4	7.2	6.5	6.0	6.2	1.20
FD fan amps	27	27	27	27	27	27	29	30	30	30	30	30	30	30	30	30	30	30	31	31	32	31	31	30	28	6.2
FD fan pressure psig	1.6	2.4	2.4	2.8	2.1	2.1	4.0	4.6	4.6	5.0	5.5	5.5	7.0	6.0	5.5	5.5	5.0	5.5	5.2	5.2	5.8	4.4	4.2	3.6	4.4	1.46
Furnace draft psig	0.64	0.64	0.64	0.60	0.60	0.54	0.60	0.58	0.59	0.58	0.58	0.55	0.55	0.70	0.60	0.60	0.60	0.60	0.60	0.62	0.70	0.60	0.64	0.61	0.61	0.042
Boiler flue gas temp °F					620	605	640	675	680	700	700	700	680	680	680	690	700	700							675*	31.1*
ESP inlet temp °F					295	300	320	320	325	325	335	335	335	335	340	340	340	340							327*	14.6*
Ambient temp °F	31	30	30	30	30	30	31	31	31	31	31	30	30	30	30	32	31	29	29	29	28	27	26	26	30	1.6
Ambient pressure inches Hg	29.03	29.00	28.98	28.96	28.94	28.94	28.97	28.96	28.92	28.89	28.88	28.85	28.84	28.83	28.80	28.79	28.78	28.76	28.82	28.82	28.82	28.82	28.82	28.82	28.88	0.079

Comments

Bottom and Fly Ash Removal
Start - 12.30A, 4.20A, 8.30A, 12.35P, 4.30P, 7.00P
Finish - 12.55A, 5.03A, 9.15A, 1.45P, 5.20P, 8.20P

Soot Blown
Start - 4.20A, 11.00A,,7.25P

RDF density - 4.5 lbs/cu ft, 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-13-80

*Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	27.0	20.0	20.0	20.0	20.0	21.0	29.0	32.0	36.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	33.0	31.2	6.11
MW Net	24.6	17.9	18.0	18.0	18.0	18.9	26.6	19.5	33.4	32.2	32.4	32.3	32.3	32.4	32.5	32.6	32.5	32.4	32.4	32.4	32.4	32.3	32.4	30.4	28.3	6.16
Steam flow rate 1000's lbs/hr	240	165	165	165	162	170	260	295	330	320	320	320	320	320	320	320	320	320	320	320	320	320	320	290	268	82.2
Steam pressure psig	850	830	850	850	836	835	865	850	860	856	855	855	855	856	855	855	856	850	860	860	860	850	860	860	853	8.6
Steam temperature °F	885	860	895	895	885	865	895	890	915	895	900	905	900	905	900	905	900	900	900	895	890	890	880	890	893	12.2
Feedwater flow rate 1000's lbs/hr	250	120	125	180	182	190	263	300	330	330	330	330	330	330	330	330	330	330	330	330	330	330	330	300	286	71.0
Feedwater temp °F	380	330	325	325	325	330	365	370	380	380	385	385	385	385	385	385	385	385	385	385	385	385	385	380	371	23.4
Fuel feed rate (coal) 1000's lbs/hr	26.1	16.7	20.3	19.6	21.0	20.5	30.1	33.4	36.5	41.5	41.5	40.5	40.0	40.0	40.5	40.5	41.0	35.4	35.6	34.8	34.0	36.8	35.4	33.2 Coal Oil	31.9 33.4 2.08	9.81 NA NA
Fuel gauge readings	419 922 804 396																									
Fuel oil	580 050																									
RDF							7.15A only 1 conveyor 7.40A both conveyors		8.35A ——				—— No RDF ——				—— Start RDF at 4.08P					9.05P System "A" off 9.25P System "A" on				
Excess air %	20	>50	38	39	38	38	18	17	14	16	17	18	18	18	18	18	16	17	19	18	18	20	17	23	23	9.8
ID fans amps	45	42	44	43	44	44	45	46	48	46	47	47	47	47	47	47	46	46	47	46	46	47	46	46	46	1.5
ID fans pressure	5.2	4.0	4.9	4.4	4.3	5.1	5.5	6.7	7.0	6.5	6.5	6.5	6.0	6.2	6.2	6.0	6.5	6.6	7.0	6.8	6.6	7.0	6.8	6.2	6.0	0.91
FD fan amps	29	27	28	27	28	28	29	30	31	30	31	30	30	31	31	31	31	30	31	30	31	31	31	30	30	1.5
FD fan pressure psig	3.1	1.6	2.6	2.0	3.2	2.9	3.1	4.8	5.2	6.8	5.8	4.8	4.8	4.8	4.8	4.8	4.8	4.0	4.6	4.3	4.4	6.0	4.4	3.6	4.2	1.20
Furnace draft psig	0.66	0.70	0.60	0.62	0.61	0.62	0.63	0.61	0.62	0.65	0.60	0.62	0.62	0.62	0.64	0.65	0.64	0.62	0.63	0.65	0.64	0.64	0.66	0.68	0.63	0.024
Boiler flue gas temp °F				620	620	605	640	660	680	700	700	700	695	700	700	705	710	720	725	720	720	725	675		686*	37.5*
ESP inlet temp °F				280	280	280	310	320	330	330	335	335	335	335	335	335	335	335	335	335	335	335	335		324*	20.1*
Ambient temp °F	26	26	26	26	25	25	24	24	25	26	29	30	31	31	31	31	31	31	31	31	29	29	29	27	28	2.6
Ambient pressure inches Hg	28.82	28.81	28.80	28.79	28.78	28.79	28.79	28.79	28.77	28.76	28.76	28.80	28.80	28.86	28.88	28.87	28.91	28.97	29.03	29.07	29.08	29.10	29.11	29.11	28.89	0.127

Comments

Bottom and Fly Ash Removal
Start - 12.30A, 4.28A, 8.30A, 3.00P, 4.35P, 8.30P, 10.30P
Finish - 1.05A, 5.12A, 9.26A, 3.50P, 5.20P, 9.35P, 10.44P

Soot Blown
Start - 4.07A

RDF density - 4.5 lbs/cu ft, 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-14-88 *Not based on 24 hr data

Time		12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW	Gross	31.8	20.0	20.0	20.0	20.0	20.0	21.0	33.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	31.8	34.0	35.0	35.0	34.0	32.0	30.0	30.5	6.25
	Net	28.4	17.8	18.0	18.0	18.0	17.9	19.0	30.5	32.7	32.3	32.4	32.4	32.4	32.2	32.3	32.4	32.4	29.2	31.4	32.3	32.4	31.2	29.4	27.4	28.0	6.01
Steam flow rate 1000's lbs/hr		269	165	165	166	165	165	177	300	315	320	310	315	315	315	315	316	310	283	300	305	337	306	280	260	270	62.8
Steam pressure psig		845	845	846	840	850	845	845	860	855	860	850	860	855	856	855	855	850	858	850	865	850	860	870	840	852	7.0
Steam temperature °F		885	885	900	900	890	860	895	900	905	905	900	900	900	910	900	900	895	895	880	900	900	900	860	900	894	12.5
Feedwater flow rate 1000's lbs/hr		275	180	180	180	176	185	180	300	330	325	325	325	325	320	320	320	320	290	310	330	345	315	295	280	281	61.3
Feedwater temp °F		370	335	335	335	335	330	335	380	380	385	385	385	386	385	385	385	380	380	380	380	390	385	380	380	371	21.8
Fuel feed rate (coal) 1000's lbs/hr		30.7	20.8	18.8	18.2	19.3	19.9	20.3	31.3	35.0	35.0	35.0	34.0	36.5	36.0	36.5	34.5	33.0	32.0	33.0	30.0	32.6	36.0	30.5	32.4 Coal Oil	30.4 30.7 3.75	6.64 NA NA
Fuel gauge readings		424 887 888 295																									
Fuel oil		690 180																									
	RDF								7.35A only 1 conveyor 7.45A both conveyors on																		
Excess air %		38	43	>50	43	42	39	36	38	33	35	38	15	36	16	18	18	37	19	18	17	20	16	18	24	24	11.3
ID fans amps		46	43	43	43	43	43	43	45	46	46	46	46	46	46	46	46	46	45	45	48	47	47	45	45	45	1.5
ID fans pressure psig		5.3	3.7	4.7	4.5	4.0	4.6	4.6	6.2	6.5	6.2	7.0	6.8	6.5	6.0	6.3	6.0	6.0	6.0	6.0	7.6	7.0	6.5	6.4	6.4	5.9	1.01
FD fan amps		30	27	27	27	27	27	27	30	30	30	30	30	30	30	30	30	30	29	30	32	31	30	29	30	29	1.5
FD fan pressure psig		4.0	2.9	2.0	1.8	1.9	2.3	2.6	4.7	4.3	4.2	4.5	4.5	4.0	3.5	4.0	4.2	4.2	3.0	4.0	6.5	5.0	4.0	3.0	4.6	3.7	1.12
Furnace draft psig		0.59	0.61	0.71	0.68	0.61	0.60	0.65	0.61	0.60	0.60	0.58	0.59	0.75	0.60	0.65	0.60	0.60	0.62	0.62	0.60	0.60	0.62	0.70	0.60	0.62	0.044
Boiler flue gas temp °F					615	620	600	630	660	680	685	685	690	665	680	680	685	690	680	690	715	700	690	650	660	669*	30.2*
ESP inlet temp					290	290	290	315	330	335	335	335	335	335	335	335	335	335	330	335	335	335	335	330	320	326*	16.0*
Ambient temp °F		23	27	21	21	21	21	21	21	26	34	40	42	49	48	50	52	54	53	51	49	46	42	41	48	37	12.6
Ambient pressure inches Hg		29.11	29.11	29.11	29.12	29.12	29.13	29.13	29.13	29.12	29.11	29.10	29.10	29.10	29.09	29.09	29.08	29.09	29.10	29.13	29.13	29.13	29.13	29.13	29.16	29.11	0.019

Comments

Bottom and Fly Ash Removal
Start - 12.27A, 4.28A, 8.82A, 12.30P, 4.30P, 8.30P
Finish - 1.00A, 5.10A, 9.25A, 1.52P, 5.00P, 9.55P

Soot Blown
Start - 4.10A, 11.20A, 8.40P

RDF density - 4.5 lbs/cu ft,
4.5 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-15-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	29.0	19.0	24.5	24.0	24.0	24.0	24.0	24.0	28.0	30.0	31.5	31.0	31.0	16.5	17.0	16.0	16.0	16.0	16.0	16.0	16.8	16.8	16.0	16.0	21.7	5.95
Net	26.6	17.0	22.4	22.0	21.9	22.0	22.0	21.6	25.8	27.2	28.9	28.4	28.4	14.4	15.0	14.0	14.0	14.0	14.3	14.2	14.3	14.2	14.2	14.2	19.6	5.68
Steam flow rate 1000's lbs/hr	245	159	212	201	201	206	205	207	240	260	280	282	278	135	138	135	136	135	135	135	135	135	135	135	186	55.06
Steam pressure psig	835	830	835	850	850	875	855	850	850	856	856	858	855	845	850	850	850	845	850	850	850	850	850	850	850	8.6
Steam temperature °F	890	880	898	880	905	885	885	885	905	900	905	860	895	895	900	895	895	885	880	890	890	870	880	880	888	11.1
Feedwater flow rate 1000's lbs/hr	256	170	220	210	208	215	215	215	245	265	285	291	283	145	145	145	145	145	146	145	145	140	145	145	194	54.0
Feedwater temp °F	370	335	355	355	355	356	355	355	355	366	375	378	375	330	325	325	315	315	320	328	320	320	320	320	330	69.4
Fuel feed rate (coal) 1000's lbs/hr	29.6	19.0	27.3	19.5	24.8	30.1	29.4	30.4	31.5	33.5	35.0	34.4	33.5	19.5	19.0	19.0	17.0	18.0	18.2	18.1	18.5	19.0	18.8	18.1	24.2	6.60
																								Coal	24.0	NA
Fuel gauge readings	427 756	430 706																						Oil	37.92	NA
	811 931	814 720	Midnight readings, 3-15-80																							
Fuel oil	580 190	581 100																								
RDF					5:00A ←										No RDF									→		
Excess air %	24	50	30	29	39	38	36	30	24	19	20	20	21	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	39	12.5
ID fans amps	45	43	44	43	44	45	44	45	45	46	46	46	46	42	42	41	31	31	41	41	41	41	41	41	42	4.0
ID fans pressure psig	5.7	5.1	4.5	5.0	4.0	5.0	3.9	3.7	5.3	5.0	5.5	5.3	5.4	3.7	3.6	3.5	3.5	3.6	3.6	3.6	3.6	3.8	3.5	3.5	4.3	0.81
FD fan amps	30	28	28	27	28	29	29	29	30	30	30	30	30	27	27	27	27	27	27	27	27	27	27	27	28	1.4
FD fan pressure psig	4.3	3.8	3.0	1.8	3.6	3.0	2.8	3.4	4.5	4.6	4.8	4.4	4.2	2.3	2.0	2.0	2.2	2.3	2.2	2.4	2.4	2.4	2.0	2.0	3.0	1.00
Furnace draft psig	0.61	0.80	0.90	0.90	0.81	0.88	0.82	0.90	0.78	0.81	0.72	0.73	0.70	0.70	0.68	0.72	0.68	0.68	0.70	0.69	0.70	0.74	0.60	0.60	0.74	0.092
Boiler flue gas temp °F					630	640	640	635	645	650	680	670	660	600	600	600	600	600	605	610	610	600	595		625*	27.3*
ESP inlet temp °F					305	305	305	310	310	320	325	325	326	290	285	285	275	270	275	275	275	275	275		295*	20.2*
Ambient temp °F	40	40	39	38	38	38	35	34	40	48	55	60	62	64	64	65	65	64	61	59	56	54	54	53	51	11.2
Ambient pressure inches Hg	29.16	29.14	29.12	29.11	29.08	29.05	29.07	29.04	29.04	29.03	29.00	29.02	28.96	28.92	28.88	28.87	28.89	27.89	28.90	28.90	28.90	28.90	28.87	28.87	28.98	0.098

Comments

Bottom and Fly Ash Removal
Start - 1.08A, 4.28A, 8.30A, 12.39P, 4.37P, 8.30P
Finish - 1.27A, 5.00A, 9.03A, 1.15P, 5.00P, 9.05P

Soot Blown
Start - 3.58A, 10.30A, 8.40P

RDF density - 3.6 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-17-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	28.0	22.0	16.0	16.0	16.0	16.0	16.0	28.0	32.5	34.0	35.0	35.0	35.0	34.5	34.5	34.5	34.5	34.5	35.0	35.0	35.0	36.0	35.0	30.6	29.6	7.74
MW Net	25.5	20.0	14.0	14.0	14.0	13.9	14.0	25.9	29.0	32.3	32.3	33.2	33.2	31.7	31.6	31.8	31.9	31.9	32.4	32.4	32.3	32.3	32.3	27.9	27.2	7.58
Steam flow rate 1000's lbs/hr	243	160	130	130	130	130	130	265	270	310	310	315	315	310	310	310	310	310	310	310	310	320	320	260	259	76.1
Steam pressure psig	845	840	850	850	850	850	860	850	835	855	855	855	855	850	850	850	850	850	860	860	850	850	850	850	850	5.3
Steam temperature °F	890	880	890	880	870	900	890	885	900	900	900	910	900	880	895	900	900	900	890	900	890	890	880	890	892	9.4
Feedwater flow rate 1000's lbs/hr	256	180	140	140	141	140	140	265	256	320	315	320	320	326	320	320	320	315	320	315	330	330	320	270	268	74.5
Feedwater temp °F	365	340	320	320	320	320	320	375	380	380	380	380	380	380	385	385	385	385	385	385	385	385	385	380	367	26.3
Fuel feed rate (coal) 1000's lbs/hr	32.4	22.0	18.6	19.4	17.6	18.9	18.9	34.5	39.6	36.5	36.6	33.5	37.5	38.0	35.0	34.5	33.5	34.0	33.0	33.4	36.8	35.2	33.5	29.6	30.9	7.23
Fuel gauge readings	434 476																							Coal	31.2	NA
Fuel oil	818 349																							Oil	2.92	NA
	581 370																									
RDF ←	—	—	—	—	No RDF	—	—	—	—	→	10:10A/ 11:05A	←	No RDF	→	Start RDF at 1:40P											
Excess air %	22	35	>50	>50	>50	>50	>50	19	21	17	18	17	20	21	17	18	16	16	18	16	20	18	16	24	26	13.3
I.D. fans amps	46	44	43	43	44	44	42	46	48	47	48	46	47	47	46	46	46	46	46	46	47	47	46	45	46	1.6
I.D. fans pressure psig	4.8	3.9	3.7	3.8	2.6	4.0	3.6	5.3	5.5	6.1	6.0	6.2	6.4	6.0	6.0	6.0	6.0	6.0	4.2	4.4	5.5	4.8	4.0	4.2	5.0	1.00
F.D. fan amps	30	27	27	27	27	27	27	30	32	30	31	30	31	31	30	30	30	30	30	31	31	31	30	30	30	1.6
F.D. fan pressure psig	3.0	1.1	2.1	2.5	2.9	2.1	2.3	4.3	5.2	5.2	5.0	4.2	5.5	5.8	4.0	4.5	4.5	4.2	4.2	4.4	5.5	4.8	4.0	4.2	4.1	1.09
Furnace draft psig	0.42	0.64	0.59	0.65	0.55	0.60	0.60	0.69	0.58	0.55	0.60	0.63	0.60	0.55	0.60	0.60	0.60	0.70	0.54	0.44	0.50	0.70	0.52	0.70	0.59	0.074
Boiler flue gas temp °F					600	600	600	645	670	680	785	695	700	695	665	675	675	685							669*	48.9*
ESP inlet temp °F					280	280	280	320	320	330	330	330	330	330	330	330	335	336							319*	21.3*
Ambient temp °F	32	32	31	31	31	30	29	29	29	29	29	32	36	36	41	41	42	42	42	41	39	36	34	34	34	4.9
Ambient pressure inches Hg	29.04	29.04	29.03	29.03	29.05	29.05	29.05	29.06	29.12	29.10	29.14	29.11	29.10	29.10	29.08	29.09	29.08	29.08	29.13	29.16	29.16	29.15	29.14	29.14	29.09	0.043

Comments

Bottom and Fly Ash Removal
Start - 4:45A, 12:40P, 7:00P
Finish - 6:00A, 1:35P, 10:00P

Soot Blown
Start - 3:30A, 12:40P, 7:00P

RDF density - none measured

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-18-80

*Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	29.0	27.0	26.5	25.5	25.5	25.5	27.0	31.0	35.5	36.0	35.5	35.0	35.0	35.0	35.0	35.0	33.0	32.5	32.0	35.0	35.8	35.8	32.8	29.0	31.8	3.84
Net	26.6	24.9	24.4	23.4	23.4	23.5	24.8	28.6	32.8	33.4	33.1	32.4	32.5	32.6	32.4	32.6	30.6	30.1	29.4	32.2	32.4	32.4	29.3	26.4	29.3	3.65
Steam flow rate 1000's lbs/hr	240	230	230	222	220	220	240	275	315	325	320	320	320	320	315	315	300	296	295	319	315	310	285	251	283	40.8
Steam pressure psig	845	835	850	855	840	850	850	850	855	860	855	855	855	850	850	850	850	845	845	855	850	855	835	855	850	6.3
Steam temperature °F	895	905	885	835	880	870	885	885	905	910	900	875	900	900	910	900	900	880	885	885	880	895	900	885	890	16.2
Feedwater flow rate 1000's lbs/hr	250	245	241	240	235	240	251	295	324	335	330	338	330	330	330	330	305	310	300	330	325	311	300	260	295	38.1
Feedwater temp °F	365	360	360	355	355	355	360	370	380	385	385	385	385	385	385	385	380	380	380	385	385	385	380	370	375	11.7
Fuel feed rate (coal) 1000's lbs/hr	30.1	31.1	27.0	24.5	28.4	23.9	28.2	32.5	39.5	38.0	36.0	34.5	35.5	35.5	33.5	35.0	33.0	32.0	31.1	32.6	32.7	32.5	31.2	29.3	32.0	3.84
Fuel gauge readings	438 297																							Coal	31.6	NA
Fuel oil	822 025																							Oil	2.50	NA
	581 440																									
RDF								7:15 A only 1 connector						1:50 P both connectors on												
Excess air	25	33	23	18	26	25	20	19	18	20	20	17	22	19	23	20	20	19	20	18	16	18	20	21	21	3.6
I.D. fans amps	45	45	44	44	44	44	44	45	47	46	46	46	46	47	46	46	46	45	46	46	46	46	47	45	46	0.98
I.D. fans pressure psig	5.3	5.2	4.7	4.8	4.6	4.4	5.0	6.0	6.6	6.3	6.3	6.5	6.0	6.5	6.8	6.8	6.0	6.0	6.0	6.4	7.0	6.0	6.0	5.1	5.8	0.77
F.D. fans amps	29	30	29	27	28	28	28	30	32	30	30	30	30	30	30	30	30	29	30	30	30	30	30	29	30	1.0
F.D. fan pressure psig	3.6	4.4	2.6	2.3	2.5	3.0	3.0	5.0	6.0	4.8	4.8	4.8	4.5	4.5	4.3	4.6	4.0	3.3	4.6	4.5	4.8	4.0	5.4	3.0	4.1	0.97
Furnace draft psig	0.65	0.45	0.69	0.65	0.57	0.45	0.61	0.60	0.60	0.70	0.60	0.70	0.60	0.50	0.75	0.53	0.65	0.50	0.40	0.60	0.80	0.65	0.51	0.60	0.59	0.098
Boiler flue gas temp °F					625	625	635	650	695	695	695	685	680	680	695	700	690	690	690	680	680	680	675		676*	24.0*
ESP inlet temp °F					305	305	310	320	330	330	330	330	330	330	330	335	330	330	330	335	335	330	320		326*	9.5*
Ambient temperature °F	33	33	33	33	34	34	34	34	37	44	51	56	62	61	64	65	66	64	62	59	56	54	50	49	49	12.8
Ambient pressure inches Hg	29.14	29.14	29.14	29.14	29.13	29.13	29.12	29.12	29.13	29.10	29.08	29.09	29.09	29.08	29.02	29.02	28.99	28.98	29.00	29.00	28.96	28.96	28.96	28.96	29.06	0.071

Comments

Bottom Ash and Fly Ash Removal
Start - 2:10A, 5:40A, 10:30A, 2:00P, 6:17P, 9:52P
Finish - 6:00A, 11:20A, 2:32P, 7:35P, 10:15P

Soot Blown
Start - 2:35A, 10:25A, 6:30A

RDF density - 3.5 lbs/cu ft, 4.0 lbs/cu ft, 3.5 lbs/ cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-19-80 | *Not based on 24 hr data

Time		12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW	Gross	21.8	25.5	25.0	25.8	24.0	25.0	27.8	31.0	36.0	35.8	34.5	35.0	36.0	35.0	35.8	35.0	36.0	31.0	33.0	36.0	35.5	35.5	32.0	23.0	31.0	5.81
	Net	19.8	23.4	22.6	22.6	21.8	22.8	24.8	28.3	32.2	32.4	32.8	32.4	32.5	32.0	32.6	32.6	32.6	28.6	30.1	33.1	32.6	32.7	29.2	20.8	27.2	6.96
Steam flow rate 1000's lbs/hr		175	220	215	212	205	208	243	292	314	315	310	310	315	320	320	320	320	280	292	340	320	319	290	190	277	52.1
Steam pressure psig		845	865	850	846	870	845	850	860	860	855	850	845	855	855	856	856	855	845	845	845	865	860	860	850	863	7.0
Steam temperature °F		875	886	895	885	890	885	895	900	895	910	900	886	894	900	900	902	900	860	880	870	875	885	880	875	888	12.1
Feedwater flow rate 1000's lbs/hr		185	232	225	236	225	220	258	295	322	315	325	325	325	326	325	328	326	296	305	349	345	325	295	200	287	50.6
Feedwater temp °F		340	360	360	355	355	350	360	395	380	385	385	385	385	386	385	385	385	386	380	396	390	390	385	350	375	16.5
Fuel feed rate (coal)		18.3	23.4	29.5	30.2	24.2	22.4	30.4	30.4	33.6	34.5	34.0	34.0	33.0	33.5	39.5	39.0	39.0	31.8	33.5	35.0	33.3	33.9	31.6	19.5	31.1	5.74
1000's lbs/hr		442 234																							Coal	31.4	NA
Fuel gauge readings		825 670																							Oil	4.17	NA
Fuel oil		581 500																									
RDF														1:10P ← No RDF → Start RDF at 4:10P													
Excess air %		40	24	19	20	24	22	20	16	15	17	15	18	16	18	19	17	17	22	18	18	12	15	18	32	20	5.9
I.D. fans amps		43	43	43	44	43	43	44	45	46	46	45	46	46	46	46	46	46	45	46	46	45	46	45	43	45	1.3
I.D. fans pressure psig		4.6	4.9	4.0	4.8	3.9	5.0	5.0	6.0	6.0	6.2	6.0	7.8	6.2	6.3	6.5	6.4	6.4	6.5	6.0	6.6	6.0	6.1	5.5	5.0	5.7	0.85
F.D. fans amps		27	28	28	28	28	28	28	30	30	29	30	31	30	30	32	31	32	30	30	30	29	30	29	26	29	1.5
F.D. fans pressure psig		2.8	3.0	3.0	2.7	2.0	2.8	3.9	4.2	3.5	4.0	4.3	6.2	4.5	4.5	6.3	5.5	4.8	4.5	4.3	5.1	3.1	4.1	3.6	2.6	3.9	1.18
Furnace draft psig		0.70	0.60	0.50	0.56	0.52	0.72	0.67	0.69	0.55	0.54	0.70	0.80	0.62	0.61	0.64	0.63	0.50	0.68	0.61	0.59	0.50	0.61	0.65	0.30	0.60	0.101
Boiler flue gas temp °F					615	620	620	630	650	680	685	690	675	675	680	690	685	700	695							666*	30.2*
ESP inlet °F					306	300	300	310	320	335	335	340	335	335	340	340	340	340	340							328*	15.9*
Ambient temp °F		48	48	45	46	45	43	43	43	44	50	59	62	62	66	68	68	69	68	68	65	61	58	59	55	56	9.3
Ambient pressure inches Hg		28.96	28.95	28.93	28.93	28.93	28.88	28.87	28.88	28.88	28.85	28.83	28.79	28.77	28.76	28.73	28.72	28.71	28.71	28.73	28.73	28.73	28.73	28.73	28.73	28.81	0.088

Comments

Bottom and Fly Ash Removal
Start - 1:50A, 5:06A, 10:30A, 1:10P, 6:30P, 9:25P
Finish - 3:25A, 5:56A, 11:06A, 1:35P, 7:54P, 10:00P

Soot Blown
Start - 3:25A, 10:15A, 6:45P

RDF density - 4.0 lbs/cu ft, 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-20-80

*Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	22.0	22.0	22.0	21.5	21.5	22.0	24.0	27.0	34.5	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	36.0	35.0	35.0	35.0	33.5	29.5	30.6	5.88
MW Net	19.8	19.4	19.6	19.2	19.3	19.7	21.8	24.2	31.7	32.4	32.5	32.0	32.5	32.5	32.4	32.5	32.6	32.0	32.2	32.3	32.3	32.2	31.1	27.1	26.8	7.68
Steam flow rate 1000's lbs/hr	190	190	190	175	180	188	200	240	315	315	320	320	320	320	320	320	315	315	319	319	319	319	300	260	273	59.8
Steam pressure psig	840	840	850	840	850	850	860	860	860	855	855	860	855	855	850	855	855	850	855	850	855	850	850	850	851	5.0
Steam temperature °F	890	880	900	880	860	880	890	890	896	905	910	870	880	900	905	910	900	896	895	896	885	885	890	900	891	12.3
Feedwater flow rate 1000's lbs/hr	200	200	200	195	210	200	210	250	320	325	330	335	330	325	328	325	325	330	326	326	340	330	305	275	222	115.4
Feedwater temp °F	350	350	350	350	340	340	360	360	380	385	385	382	382	385	385	385	385	385	385	385	385	385	380	370	372	16.8
Fuel feed rate (coal)	16.9	20.0	24.5	26.0	24.0	24.6	29.8	32.4	38.1	38.0	39.0	37.2	37.0	37.0	36.5	37.0	37.0	39.6	39.6	40.1	41.6	39.0	36.5	34.0	33.6	7.06
1000's lbs/hr	446 122	450 244																						Coal	34.4	NA
Fuel gauge readings	829 315	833 406	Midnight readings, 3-20-80																					Oil	20.42	NA
Fuel oil	581 600	582 090																								
RDF			2:30A →				No RDF					11:00A → ← 11:35A						No RDF						→		
Excess air %	36	40	42	40	40	36	25	24	22	22	20	19	23	21	22	21	23	21	21	21	20	26	24	32	27	7.7
I.D. fans amps	44	43	43	43	44	44	44	45	47	47	46	46	47	47	47	47	47	48	48	48	48	48	48	48	46	1.8
I.D. fans pressure psig	5.8	4.8	4.8	4.0	4.4	4.7	5.4	4.8	6.5	6.5	6.4	6.6	6.5	6.5	6.	6.5	6.5	6.5	7.0	5.6	7.0	6.5	6.0	5.8	5.9	0.90
F.D. fans amps	28	28	28	27	28	28	29	29	32	31	31	30	30	31	31	31	31	32	32	32	32	32	31	30	29	6.4
F.D. fans pressure psig	3.5	3.2	3.2	3.5	2.8	2.6	3.3	3.1	5.8	6.0	5.8	4.0	5.5	6.5	5.5	5.5	6.0	6.5	6.1	6.2	6.1	6.0	5.0	4.0	4.8	1.32
Furnace draft psig	0.54	0.80	0.60	0.40	0.60	0.78	0.70	0.68	0.53	0.55	0.60	0.70	0.62	0.68	0.52	0.60	0.55	0.65	0.50	0.50	0.50	0.60	0.62	0.60	0.60	0.093
Boiler flue gas temp °F					615	620	625	630	695	705	710	670	680	690	700	700	705	710	715	720	680	685	680	680	681*	32.8*
ESP inlet °F					295	296	300	320	325	325	330	330	330	330	335	335	335	330	330	330	330	330	330	315	324*	12.7*
Ambient temp °F	50	50	46	46	46	47	44	43	43	42	42	42	44	46	51	52	51	50	45	44	44	42	42	39	44	9.2
Ambient pressure inches Hg	28.72	28.72	28.82	28.82	28.83	28.86	28.90	28.90	28.94	28.96	28.96	28.96	28.97	28.95	28.93	28.92	28.93	28.97	28.98	28.97	28.99	29.01	29.03	29.03	28.92	0.085

Comments

Bottom and Fly Ash Removal
Start - 1:30A, 5:05A, 10:45A, 1:15P, 8:33P
Finish - 11:35A, 1:35P, 9:44P

Soot Blown
Start - 3:00A, 10:15A, 7:10P

RDF density - 3.5 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-22-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross	22.0	22.0	22.0	22.5	23.0	23.0	23.0	23.0	29.0	32.0	34.0	34.0	34.5	34.0	32.5	32.0	32.0	33.0	33.0	35.0	34.5	34.5	32.0	30.0	29.4	5.16
MW Net	19.9	19.9	19.9	20.4	20.9	21.0	20.8	20.8	26.8	29.7	31.6	31.4	32.0	31.4	30.1	29.6	29.6	30.6	30.3	32.3	31.8	31.7	29.3	27.4	27.1	4.95
Steam flow rate 1000's lbs/hr	180	180	180	190	195	200	195	195	255	288	310	320	310	307	285	280	285	290	295	312	330	310	285	265	260	51.3
Steam pressure psig	860	850	860	860	850	850	860	850	868	850	850	880	850	850	850	850	850	850	860	860	850	850	850	850	853	7.4
Steam temperature °F	890	900	890	870	870	870	880	900	905	900	900	910	890	890	900	905	900	900	890	890	900	880	880	880	891	11.8
Feedwater flow rate 1000's lbs/hr	200	200	200	210	210	200	206	200	263	293	310	315	320	315	300	295	295	300	302	322	330	325	295	265	270	50.5
Feedwater temp °F	340	340	340	340	340	340	340	340	365	375	380	385	375	380	380	380	380	380	380	385	380	380	380	365	365	18.9
Fuel feed rate (coal)	19.3	21.2	19.4	20.8	20.3	20.2	18.0	25.8	28.0	32.0	35.5	36.1	36.0	38.5	35.5	37.0	38.8	39.8	38.5	40.2	40.5	40.1	38.6	33.5	31.3	8.32
1000's lbs/hr	453 901																							Coal	31.1	NA
Fuel gauge readings	836 954																							Oil	26.67	NA
Fuel oil	582 760																									
RDF												12:12P						No RDF								
Excess air %	27	27	27	25	27	27	26	25	17	22	21	19	21	15	18	19	18	18	20	20	20	20	20	19	22	3.8
I.D. fans amps	42	42	42	42	43	43	43	43	44	45	46	47	46	46	46	46	46	46	46	46	46	46	46	45	45	1.7
I.D. fans pressure psig	4.6	4.0	3.8	4.4	4.0	4.6	4.2	4.8	4.7	6.2	6.2	6.3	6.3	6.0	5.8	5.5	5.5	5.5	6.0	6.4	6.5	6.0	5.7	5.2	5.3	0.87
F.D. fans amps	27	28	27	27	27	28	27	27	29	30	30	31	30	30	30	30	30	30	30	31	31	31	30	30	29	1.5
F.D. fans pressure psig	3.0	3.0	2.4	3.2	3.4	3.6	3.0	2.0	3.8	4.6	4.5	4.7	4.8	4.8	4.5	4.0	4.5	4.8	4.9	5.8	5.8	5.0	4.0	3.8	4.1	0.99
Furnace draft psig	0.68	0.44	0.40	0.74	0.40	0.68	0.60	0.70	0.47	0.45	0.65	0.60	0.70	0.68	0.68	0.65	0.50	0.58	0.55	0.56	0.65	0.58	0.62	0.66	0.59	0.101
Boiler flue gas temp °F						610	610	615	640	660	685	700	680	675	670	675	670	680							659*	30.4*
ESP inlet °F						300	300	300	315	320	330	330	330	330	330	325	325	325							320*	12.2*
Ambient temp °F	36	34	34	33	33	33	34	33	35	36	38	40	44	45	46	50	50	50	46	43	41	41	39	39	40	5.9
Ambient pressure inches Hg	29.21	29.21	29.21	29.17	29.18	29.18	29.18	29.18	29.15	29.14	29.11	29.08	29.05	29.02	29.00	28.98	28.97	28.96	28.86	28.87	28.87	28.87	28.87	28.87	29.04	0.134

Comments

Bottom and Fly Ash Removal
Start - 2:00 A, 5:00A, 11:30A, 1:00P, 8:00P
Finish - 1:26P,

Soot Blown
Start - 2:35A, 11:30A, 7:00P

RDF density - 3.5 lbs/cu ft, 4.5 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-23-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross Net	25.0 22.4	17.0 15.8	17.0 15.8	17.0 15.2	17.0 15.2	17.0 15.2	17.0 15.1	17.0 15.2	17.0 15.2	17.0 15.2	17.0 15.2	17.0 15.4	17.0 15.4	17.0 15.2	17.0 15.3	17.0 15.4	17.0 15.4	17.0 15.4	20.0 18.3	20.0 18.0	20.0 18.0	20.0 18.0	20.0 17.9	20.0 18.0	18.1 16.2	1.98 1.80
Steam flow rate 1000's lb/hr	210	145	144	144	144	144	145	145	142	142	143	144	144	144	144	142	144	144	160	168	168	168	168	160	153	16.2
Steam pressure psig	850	840	850	850	845	850	850	850	845	850	845	850	850	855	850	855	855	855	860	860	860	860	860	860	852	5.7
Steam temperature °F	880	880	890	850	880	890	880	880	890	900	885	895	890	890	880	890	890	895	880	890	870	880	880	880	884	10.0
Feedwater flow rate 1000's lbs/hr	220	152	155	155	152	160	150	150	160	150	150	150	165	150	151	150	150	150	180	180	180	180	180	180	162	17.8
Feedwater temp °F	340	320	320	320	320	320	320	320	320	320	325	320	320	320	320	320	320	325	330	340	330	330	330	340	325	7.1
Fuel feed rate (coal) 1000's lbs/hr Fuel gauge readings Fuel oil	26.2 457 717 840 602 883 406	19.5	19.6	19.5	19.5	19.6	19.0	20.2	19.4	19.8	19.6	21.0	21.0	21.0	20.0	20.0	20.5	19.5	22.0	22.6	22.9	23.0	22.6	22.2 Coal Oil	20.8 20.4 33.33	1.71 NA NA
RDF													No RDF													
Excess air %	19	>60	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	>50	41	40	29	29	26	26	26	28	42	11.0
I.D. fans amps	44	43	43	43	43	43	43	43	43	43	43	42	42	42	43	42	41	41	42	42	42	42	42	42	42	0.7
I.D. fans pressure psig	4.0	4.0	4.0	3.4	3.7	4.0	3.8	3.8	3.7	3.7	3.6	3.8	4.5	3.8	3.7	3.8	3.5	3.5	3.8	3.8	3.7	3.8	3.6	3.7	3.8	0.22
F.D. fan amps	29	28	28	27	27	27	28	27	27	27	27	27	28	27	27	27	26	26	27	27	27	27	27	27	27	0.6
F.D. fan pressure psig	2.0	2.7	2.7	2.7	2.2	2.5	2.2	2.3	2.1	2.3	2.1	2.3	2.8	2.4	2.1	2.2	1.8	1.6	2.2	2.2	2.2	2.5	2.3	2.5	2.3	0.30
Furnace draft psig	0.54	0.60	0.64	0.58	0.54	0.67	0.60	0.64	0.58	0.51	0.56	0.60	0.40	0.63	0.60	0.58	0.64	0.64	0.62	0.65	0.57	0.60	0.55	0.56	0.59	0.057
Boiler flue gas temp °F								600	600	600	600	605	590	600	600	600	595	595							599*	3.9*
ESP inlet °F								280	280	280	280	280	280	280	280	280	280	280							280*	0*
Ambient temp °F	40	41	39	39	37	36	36	36	36	36	36	37	37	38	38	40	40	38	37	36	36	36	36	36	37	1.6
Ambient pressure inches Hg	28.87	28.96	28.95	28.94	28.93	28.92	28.92	28.99	28.98	28.98	29.01	28.99	28.97	28.97	28.96	28.95	28.96	28.96	29.00	29.00	29.01	29.01	29.01	29.01	28.97	0.036

Comments

Bottom and Fly Ash Removal
Start - 5:00A, 12:55P, 8:10P
Finish - 6:36A, 1:30P,

Soot Blown
Start - 2:30A, 11:15A, 7:00P

RDF density - No RDF

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-24-80 *Not based on 24 hr data

Time	12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW Gross Net	20.0 18.0	20.0 18.0	18.0 16.0	17.0 15.0	17.0 15.2	17.8 15.2	17.8 15.2	30.0 27.3	35.0 32.3	35.0 32.4	35.0 32.6	35.0 32.4	34.5 32.0	35.0 32.6	34.5 33.0	36.0 32.5	35.0 32.4	35.0 32.5	36.0 32.5	35.0 32.5	35.0 32.5	35.0 32.5	35.0 32.4	32.5 30.0	29.7 27.4	7.77 7.56
Steam flow rate 1000's lbs/hr	165	165	150	148	148	148	148	260	315	310	310	305	310	315	310	310	310	315	320	320	318	318	318	290	264	73.6
Steam pressure psig	860	860	860	860	860	860	860	860	860	855	855	840	850	860	850	860	860	855	860	860	860	860	860	860	858	4.9
Steam temperature °F	888	900	880	880	900	890	880	890	890	904	904	900	890	890	900	915	880	890	890	900	860	890	890	890	891	11.2
Feedwater flow rate 1000's lbs/hr	180	180	160	160	164	155	155	270	323	320	320	312	315	325	320	325	320	320	328	328	332	330	328	290	273	72.5
Feedwater temp °F	340	340	330	330	330	320	320	3 0	3 0	380	380	380	380	385	385	385	385	385	385	390	390	385	390	380	367	25.4
Fuel feed rate (coal 1000's lbs/hr Fuel gauge readings Fuel oil	22.8 460 266 842 965 504 200	22.8	20.2	19.4	20.3	19.0	20.1	33.7	37.5	37.0	37.0	34.5	32.0	33.0	33.0	34.5	33.4	39.5	41.1	42.8	42.5	41.7	40.6	37.0 Coal Oil	32.3 32.8 20.42	8.26 NA NA
RDF ←					No RDF						← Start RDF at 10:27A					4:10P ←				No RDF →						
Excess air %	28	29	46	45	41	46	45	24	19	20	18	19	17	18	17	14	16	19	18	19	19	19	17	19	25	10.0
I.D. fans amps	42	43	43	43	42	42	43	46	47	47	47	46	48	48	48	46	46	46	47	47	47	47	47	43	46	2.2
I.D. fans pressure psig									6.1	5.8	5.8	6.5	6.1	6.5	6.2	6.2	6.2	6.0	6.2	6.2	6.5	6.0	6.0	5.5	6.1*	0.27*
F.D. fans amps	27	27	27	27	27	27	27	29	31	30	30	31	30	30	30	30	30	30	31	31	31	31	31	31	29	1.7
F.D. fan pressure psig	2.3	3.0	2.8	3.0	3.2	2.6	2.8	3.8	4.6	4.5	4.8	4.8	4.5	4.6	4.4	4.6	4.0	4.2	4.8	5.3	5.8	5.4	4.5	4.8	4.1	0.92
Furnace draft psig	0.55	0.57	0.60	0.50	0.60	0.58	0.58	0.50	0.68	0.38	0.62	0.47	0.62	0.55	0.50	0.40	0.55	0.55	0.50	0.58	0.52	0.40	0.55	0.48	0.53	0.073
Boiler fuel gas temp °F					600	595	595	655	680	670	685	700	685	660	670	680	680	685							660*	36.1*
ESP inlet temp °F					280	280	280	335	330	330	336	336	335	335	335	335	335	335							322*	23.1*
Ambient temp °F	36	35	35	36	36	36	36	36	36	36	36	35	35	36	38	38	38	38	37	37	37	36	36	35	36	1.0
Ambient pressure inches Hg	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.96	28.99	28.98	29.01	29.02	29.04	29.04	29.06	29.06	29.06	29.08	29.13	29.13	29.13	29.18	29.18	29.18	29.04	0.079

Comments

Bottom and Fly Ash Removal
Start - 1:00A, 5:00A, 9:00A, 1:01P, 5:05P, 9:05P
Finish - 9:35A, 2:06P,

Soot Blown
Start - 3:00A, 11:45A, 2:20P, 7:20P

RDF density - 4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-25-80 *Not based on 24 hr data

Time		12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW	Gross	22.0	18.0	18.0	18.0	18.0	18.0	18.0	28.0	35.0	35.0	35.0	35.0	35.0	35.0	34.0	34.5	36.0	35.0	36.0	35.0	35.0	36.0	35.0	25.5	29.6	7.54
	Net	19.8	16.2	16.2	16.2	16.2	16.2	16.1	25.8	32.3	32.2	32.6	32.5	32.6	32.6	31.4	32.1	32.3	32.3	32.5	32.3	32.5	32.6	32.5	23.7	27.2	7.21
Steam flow rate 1000's lbs/hr		180	148	148	160	155	155	156	250	317	315	318	315	315	310	308	312	312	312	312	311	312	312	313	252	262	71.9
Steam pressure psig		860	850	850	850	850	850	860	840	860	855	855	855	855	855	845	850	850	850	860	850	810	850	853	850	852	4.8
Steam temperature °F		870	890	880	880	880	880	880	890	900	905	900	900	880	890	900	900	900	900	900	905	882	900	900	880	892	10.7
Feedwater flow rate 1000's lbs/hr		230	158	160	160	160	160	165	260	325	320	325	325	325	320	325	324	320	320	320	318	325	324	320	280	272	71.4
Feedwater temp °F		340	320	320	320	320	320	320	360	380	380	380	380	385	380	385	385	383	383	383	383	382	382	382	380	364	27.6
Fuel feed rate (coal) 1000's lbs/hr Fuel gauge readings Fuel oil		21.9 464 277 846 818 584 690	21.0	21.0	21.4	21.5	21.5	21.5	33.9	34.7	35.3	33.0	33.0	33.0	34.0	34.0	34.0	35.7	40.3	38.7	39.9	39.5	37.5	39.0	30.0 Coal Oil	31.8 31.8 28.33	7.66 NA NA
RDF ←— No RDF —→ Start RDF at 7:40A																		4:05P reduced RDF flow until 8:00A, 3-26-80							10:00P system "B" OFF 10:22P System "B" ON		
Excess air %		38	>50	>50	>50	>50	>50	>50	22	22	19	20	18	18	19	19	17	16	17	15	18	17	15	18	18	27	14.3
I.D. fans amps		43	45	43	44	45	45	45	46	48	47	48	48	48	48	48	48	46	46	46	46	46	46	46	45	46	1.6
I.D. fans pressure psig		3.8	5.0	3.5	3.4	4.8	4.8	4.6	6.0	7.6	7.0	6.4	6.6	6.5	6.2	6.2	6.2	6.0	6.5	6.5	6.5	6.3	6.3	6.4	4.5	5.7	1.14
F.D. fans amps		28	28	28	28	28	28	28	30	31	31	30	30	30	30	30	30	30	30	31	31	32	31	31	29	30	1.3
F.D. fan pressure psig		3.0	3.0	3.0	3.0	2.9	3.1	3.4	5.0	4.6	4.9	4.3	4.8	5.0	5.5	4.4	4.5	4.2	4.5	4.7	4.7	5.0	4.8	5.0	3.4	4.2	0.84
Furnace draft psig		0.53	0.90	0.43	--	--	--	--	--	--	0.57	0.52	0.55	0.60	0.49	0.67	0.61	0.55	0.63	0.63	0.60	0.57	0.50	0.50	0.40	0.57*	0.108*
Boiler flue gas temp °F							605	610	640	690	685	690	700	690	665	670	680	685	695							670*	31.6*
ESP inlet temp °F							280	280	310	330	330	330	330	335	335	335	335	335	335							323*	2.03*
Ambient temp °F		35	32	31	31	31	31	31	29	33	34	36	42	44	43	44	45	46	46	46	45	45	43	41	40	38	6.3
Ambient pressure inches Hg		29.18	29.18	29.18	29.18	29.18	29.18	29.18	29.18	29.22	29.21	29.18	29.19	29.18	29.17	29.15	29.14	29.14	29.12	29.15	29.14	29.15	29.15	29.15	29.15	29.17	0.024

Comments

Bottom and Fly Ash Removal
Start - 1:00A, 5:00A, 9:00A, 1:01P, 5:00P, 7:00P, 9:05P
Finish - 9:45A, 2:15P, 5:43P, 7:40P, 9:50P

Soot Blown
Start - 2:20A, 11:35A, 7:00P

RDF density - 3.5 lbs/cu ft,
4.0 lbs/cu ft

PROCESS DATA

AMES MUNICIPAL POWER PLANT

UNIT NO. 7

Date 3-26-80 *Not based on 24 hr data

Time		12M	1A	2A	3A	4A	5A	6A	7A	8A	9A	10A	11A	12N	1P	2P	3P	4P	5P	6P	7P	8P	9P	10P	11P	Mean	σ
MW	Gross	22.0	21.5	21.5	21.5	21.5	21.5	21.5	30.0	34.5	34.5	36.0	34.5	35.0	34.5	35.0	36.0	35.0		35.0	35.0	35.0	35.0	35.0	32.0	30.5*	6.17*
	Net	20.0	19.5	19.5	19.5	19.5	19.5	19.5	17.5	31.8	31.8	33.4	32.0	32.5	32.0	32.4	32.5	32.5		32.3	32.4	32.2	32.3	32.3	29.3	27.7*	6.29*
Steam flow rate 1000's lbs/hr		* 180	180	180	180	180	180	178	270	317	316	310	310	310	320	312	310	310	315	312	312	316	312	312	290	250	79.1
Steam pressure psig		850	850	850	850	850	850	850	860	860	855	850	860	855	850	855	855	855	860	860	860	860	860	850	850	864	4.4
Steam temperature °F		880	860	890	880	890	890	890	900	900	900	910	900	900	880	920	902	910	880	890	890	840	880	890	880	890	16.6
Feedwater flow rate 1000's lbs/hr		190	190	190	195	190	190	190	270	327	323	328	328	320	330	328	324	322	327	325	325	330	322	322	305	283	61.6
Feedwater temp °F		340	340	340	340	340	340	340	340	380	385	380	380	380	380	380	385	385	386	385	385	385	385	386	385	369	20.9
Fuel feed rate (coal)		19.0	19.0	18.5	21.0	18.7	19.4	19.4	25.2	34.4	35.1	35.0	33.5	33.0	34.0	40.0	34.0	34.5	33.6	33.5	34.2	33.5	34.0	34.9	33.4	29.6	7.16
1000's lbs/hr		460 170																							Coal	31.9	NA
Coal gauge readings		850 561																							Oil	1.67	NA
Fuel oil (gallons/hr)		585 370													No ROF												
ROF		Reduced ROF flow								8:00A resume normal ROF flow					1:30P ←— Start ROF at 2:12P												
Excess air %		34	28	30	27	27	28	27	28	19	18	18	19	18	18	19	19	19	17	20	20	19	20	20	20	22	4.8
I.D. fans amps		44	44	44	44	44	44	42	45	47	47	46	46	46	46	46	48	46	46	46	46	46	46	46	45	45	1.3
I.D. fans pressure psig		3.8	3.8	4.0	4.0	4.0	4.5	4.4	3.2	6.1	6.1	7.0	6.8	6.3	6.5	6.2	6.8	6.5	6.0	6.5	6.6	6.7	6.2	6.4	6.5	5.6	1.24
F.D. fans amps		27	27	27	27	28	27	27	30	31	31	30	30	30	30	30	30	30	30	31	31	30	30	30	30	29	1.5
F.D. fan pressure psig		2.0	1.9	1.8	2.2	1.7	1.8	2.0	4.4	4.4	4.9	4.9	4.9	4.5	5.0	3.6	5.2	5.2	4.2	4.6	5.0	4.4	4.8	5.0	4.5	3.9	1.37
Furnace draft psig		0.34	0.50	0.40	0.50	0.60	0.70	0.72	0.60	0.49	0.43	0.60	0.45	0.48	0.55	0.58	0.52	0.49	0.60	0.52	0.65	0.60	0.44	0.50	0.55	0.53	0.092
Boiler flue gas temp °F		620	630	620	600	600	600	685	665	690	695	700	700	700	665	680	690	690	690	700	700	665	675	680	670	664	37.1
ESP inlet temp °F		290	290	290	290	290	290	290	320	330	325	320	325	325	325	330	330	330	325	325	325	325	325	325	320	315	16.6
Ambient temp °F		38	36	36	36	35	36	35	34	34	36	40	40	45	44	45	45	45	45	43	43	42	40	39	38	40	4.1
Ambient pressure inches Hg		29.21	29.21	29.21	29.20	29.20	29.20	29.23	29.23	29.23	29.23	29.23	29.19	29.17	29.15	29.12	29.11	29.12	29.11	29.12	29.10	29.14	29.14	29.14	29.14	29.17	0.046

Comments

Bottom and Fly Ash Removal
Start - 1:00A, 5:00A, 9:00A, 1:02P, 5:10P, 7:20P,
Finish - 9:55A, 2:40P,

Soot Blown
Start - 2:10A, 11:45A, 7:06P

ROF density - 3.5 lbs/cu ft,
3.0 lbs/cu ft

APPENDIX B

TRW FIELD TEST REPORT FOR THE CHICAGO NORTHWEST INCINERATOR, UNIT NO. 2

PILOT TEST PROGRAM
CHICAGO NORTHWEST INCINERATOR
BOILER NO. 2

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TRW ENVIRONMENTAL ENGINEERING DIVISION
TRW, INC.

EPA Contract 68-02-2197

EPA Project Officer: Michael Osborne

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, N.C. 27711

CONTENTS

FIGURES

TABLES

ACKNOWLEDGEMENTS

This sampling and field measurement work was performed for the U.S. Environmental Protection Agency (EPA) under Contract No. 68-02-2197. The program was sponsored jointly by the Office of Pesticides and Toxic Substances in cooperation with the Office of Research and Development (ORD) of the EPA.

The ORD-sponsored portion of the program was directed by Mr. Michael C. Osborne, Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina. The Office of Pesticides and Toxic Substances - sponsored portion of this study was directed by Mr. Martin Halper, Washington, D.C.

Three contractors participated in the overall test program, namely, TRW Inc., Midwest Research Institute (MRI) and Research Triangle Institute (RTI). TRW Inc. was responsible for the field testing; MRI had responsibility for the sampling analysis; and RTI had overall responsibility for the statistical design of the test program.

Many individuals contributed to the sampling, testing, data reduction and report preparation for this study. Mr. Birch Matthews had overall responsibility for this program at TRW Inc. He was assisted in his management activities by Dr. Chris Shih and Mr. Don Price. The Field Team Leader was Mr. Dave Moore and the field sampling team members were Mr. J. Berger, Mr. M. Drehsen, Mr. J. Gordon, Mr. W. Kendrick, Mr. J. McReynolds, Ms B. Riley, Mr. T. Rooney, Mr. D. Savia, Mr. B. Wessel and Mr. W. Wright. The Process Engineers were Mr. P. Bakshi and Mr. T. Sarro.

The Chicago Northwest Incinerator personnel who provided significant assistance in completing the study were: Mr. Emil Nigro, the Supervising Engineer of the city of Chicago, Bureau of Sanitation; Mr. Stanley Oenning, the Chief Operations Engineer at the plant; and Mr. Gerry Golubski, Plant Chemist. In addition, there were numerous other plant personnel who provided assistance during the field testing. Their efforts are greatly appreciated and their contribution is hereby acknowledged.

1.0 INTRODUCTION

This document describes the sampling and monitoring activities performed at the Chicago Northwest Incinerator, Boiler No. 2. The sampling and field measurement work was part of an overall pilot scale test program sponsored by the Office of Pesticides and Toxic Substances in cooperation with the Office of Research and Development, of the U.S. Environmental Protection Agency.

The ultimate objective of the pilot scale test program is to develop an optimum sampling and analysis protocol to characterize polychlorinated organic compounds which may be emitted in trace quantities through conventional combustion of fossil fuels and refuse. The genesis of the program is an industrial study by Dow Chemical Company and two groups of European investigators reporting emissions of polychlorincted dibenzo-p-dioxins (PCDD), dibenzofurans (PCDF) and biphenyls (PCB) from stationary conventional combustion sources.

The immediate objective of the sampling and field measurements program is the specification of procedures and equipment to obtain sufficient multimedia samples for the subsequent analytical protocol, and to satisfy the program statistical design requirements. In this respect, the TRW Environmental Engineering Division of TRW, Inc., was one of three contractors participating in the overall EPA program and was responsible for the acquisition of samples and measurements in the field.

The sampling was oriented toward acquiring multimedia samples for organic compound analysis by Midwest Research Institute (MRI). Compounds of particular interest included:

Benzo [a] pyrene	Chrysene
Pyrene	Indeno [1,2,3-cd] pyrene
Fluoranthene	Benzo [g,h,i] perylene
Phenanthene	Anthracene

In addition, MRI is to make a determination of total organic chlorine emissions from the acquired samples. Potentially, selected samples are to be analyzed for polychlorinated dibenzo-p-dioxins, dibenzofurans and biphenyls.

Instrumentation for on-line combustion gas stream monitoring was part of the test program. In addition, incinerator process information was also gathered. This information together with the monitoring data were acquired to assist in evaluating and interpreting chemical analysis results.

This report contains all the field data for the Chicago Northwest Incinerator pilot test program conducted in May 1980. Data provided include the following:

- Chlorinated hydrocarbon collection using a modified EPA Method 5 train and Method 5 sampling methodology.
- Gas velocities using EPA Method 2,
- Continuous monitoring for CO_2, O_2, and CO and THC,
- Particulate collection for inorganic analysis utilizing EPA Method 5.
- Process data.

The test program followed was described in the Pilot Test Program, Chicago Northwest Incinerator, Boiler No. 2, site test plan. Deviations from this program are documented and explained in their respective sections of this report.

2.0 SUMMARY

2.1 SAMPLING AND ANALYSIS

The field test activity took place from April 30, 1980 to May 23, 1980. All required tests were completed and all recovered samples were sent to Gulf South Research Institute (GSRI) for analysis. MRI had subcontracted this part of their assignment to GSRI.

A summary of tests conducted including any significant commentary is presented in Table 2-1. A summary of the reduced data on a daily basis as calculated from the field data sheets is presented in Table 2-2. Data listed are corrected to standard conditions, i.e., 20°C and a barometric pressure of 29.92 inches mercury.

Sampling and calibration procedures are described in Sections 4, 5 and 6. Hourly data is provided in the appendices. Appendix A contains continuous monitoring data; Appendix B contains field data; and Appendix C contains sample inventory sheets supplied by GSRI.

2.2 PROCESS DATA

For every day of inlet or outlet testing, a 24 hour record of process data was obtained. This information is provided in the daily process data sheets in Appendix D. Most of this data was obtained from instrumentation in the control room. The parameters considered important to the operation of Boiler No. 2, and for which instrumentation was available include steam flow rate, steam pressure, feedwater flow rate, feedwater temperature, combustion air flow rate, combustion air temperature, % oxygen, I.D. fan pressure, F.D. fan pressure, furnace draft, and furnace temperature. No data were available for steam temperature, excess air, or the power consumption of the fans.

A chart recording instrument located in the control room provided continuous instantaneous readings for steam flow rate, feedwater flow rate, and combustion air flow rate. These were read directly from the instrument in 1000's of pounds per hour, 1000's of pounds per hour, and 1000's of cubic feet per hour, respectively. These are given in Appendix D under the heading "chart recorder" for each of the three parameters.

TABLE 2-1. DAILY SAMPLING SUMMARY

Date (1980)	Test No.	Sampling locations	Test comments
5/4	1	Inlet-North	Test started at 0835 hours and ran for 350 minutes. Low volume was obtained. Test was discontinued because of unsuccessful leak checks after filter replacement.
		Inlet-South	Test started at 0835 hours and ran for 193 minutes. Low volume was obtained. Battelle trap also appeared to plug up and was therefore changed. However, this did not occur during remaining tests. Filter blockage also occurred probably due to filter oven temperature not being hot enough (250°F). At 1600 hours the plant had to shut down due to boiler leaks. Test quality was fair.
		Outlet-North	Test started at 0825 hours and ran for 404 minutes. No significant problems occurred. Test quality was good.
		Outlet-South	Test started at 0820 hours and ran for 375 minutes. No new leak rate was obtained at filter change. New filter housing was found to be warped which caused the leak problem. Test quality was good.
		Hi Volume Sampler	Sample was lost due to the wind blowing the filter out of the filter holder.
		Continuous monitors	No problems were encountered. Test quality was good.
5/6	2	Inlet-North	Test started at 1230 hours and ran for 525 minutes. There were no significant problems. Test quality was good.
		Inlet-South	Test started at 1230 hours and ran for 525 minutes. There were no significant problems. Test was inadvertently stopped with only 21 of the required 24 points traversed. However, both gas volume and particulate collections were sufficient. Test quality was good.
		Outlet-North	Test started at 1235 hours and ran for 500 minutes. There were no significant problems. Test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling locations	Test comments
5/6	2	Outlet-South	Test started at 1230 hours and ran for 500 minutes. Probe was found to be cracked at the end of test. However, based on a moisture calculation of only 3% (vs. 12% in other test), it appears that the probe cracked during the first 280 minutes. The probe was switched and the test continued an additional 200 minutes. Test quality was poor as only air was sampled for 50% of the test.
		Hi Volume Sampler	Test started at 1311 hours and was stopped at 2325 hours. Test quality was good.
		Continuous monitors	Test quality was good.
5/7	3	Inlet-North	Test started at 0835 hours and ran for 420 minutes. No problems were encountered. Test quality was good.
		Inlet-South	Test started at 0837 hours and ran for 480 minutes. No problems were encountered. Test quality was good.
		Outlet-North	Test started at 0930 hours and ran for 500 minutes. No problems were encountered. Test quality was good.
		Outlet-South	Test started at 0955 hours and ran for 500 minutes. No problems were encountered. Test quality was good.
		Hi Volume Sampler	Test started at 1215 hours and was stopped at 2000 hours. Test quality was good.
		Continuous monitors	No problems were encountered. Test quality was good.
5/8	4	Inlet-North	Test started at 0845 hours and ran for 420 minutes. No problems were encountered. Test quality was good.
		Inlet-South	Test started at 0832 hours and ran for 480 minutes. No problems were encountered. Test quality was good.
		Outlet-North	Test started at 0930 hours and ran for 500 minutes. Low moisture obtained because of cracked probe.
		Outlet-South	Test started at 0925 hours and ran for 500 minutes. No problems were encountered. Test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling locations	Test comments
5/8	4	Hi Volume Sampler	Test started at 1015 hours and was stopped at 1910. Test quality was good.
		Continuous monitors	No problems were encountered. Test quality was good. CO readings were suspect, refer to 5/9/80 continuous monitoring data.
5/9	5	Inlet-North	Test started at 0820 hours and ran for 480 minutes. After 180 minutes the sampling time was increased from 20 to 25 minutes per point to collect sufficient sample volume. Boiler was operating at lower load conditions during this period. Test quality was good.
		Inlet-South	Test started at 0805 hours and ran for 542 minutes. After 267 minutes the sampling time was increased from 20 to 25 minutes per point. (See Inlet-North above). Test quality was good.
		Outlet-North	Test started at 0905 hours and ran for 500 minutes. Test quality was good.
		Outlet-South	Test started at 0920 hours and ran for 500 minutes. Test quality was good.
		Hi Volume Sampler	Test started at 0915 hours and was stopped at 1850 hours. Test quality was good.
		Continuous monitors	CO was exhibiting drift problems due to exhausted dessicant. Dessicant was therefore replaced. Previous days (5/8/80) data were suspect as CO dropped to lower level after dessicant changeout. Test quality was good.
5/10	6	Inlet-North	Test started at 0815 hours and ran for 420 minutes. No problems were encountered. Test quality was good.
		Inlet-South	Test started at 0810 hours and ran for 480 minutes. No problems were encountered. Test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling location	Test comments
5/10	6	Outlet-North	Test started at 0915 hours and ran for 480 minutes. No problems were encountered. However, test was halted one point from completion due to stormy weather. There was little effect on test data. Test quality was good.
		Outlet-South	Test started at 0840 hours and ran for 550 minutes. No problems were encountered. Test quality was good.
		Hi Volume Sampler	Test started at 1100 hours and was stopped at 1900 hours. (Problems due to wind were encountered but the sample was not destroyed). Results were fair to good.
		Continuous monitors	CO was taken off line due to span and balance problems. Remaining data were good.
5/11	7	Inlet-North	Test started at 0828 hours and ran for 462 minutes. No problems were encountered. Test quality was good (changed sampling time to 22 minutes per point for inlet trains prior to starting test).
		Inlet-South	Test started at 0934 hours and ran for 528 minutes. No problems were encountered. Test quality was good. Excessive number of filters were used during this test day for both inlet trains.
		Outlet-North	Test started at 0900 hours and ran for 360 minutes. Due to excessive amount of time needed to correct malfunctioning equipment, the north train was utilized for only 20 points instead of the normal 25 points. Total volume sampled for north and south trains was 20 m^3. Test quality was good. (Changed sampling time to 18 minutes per point prior to start of test).
		Outlet-South	Test started at 0915 hours and ran for 540 minutes. South train traversed 30 points (see comments for Outlet-North train for 5/11/80). No problems were encountered and test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling locations	Test comments
5/11	7	Hi Volume Sampler	Test started at 1014 hours and was stopped at 1930 hours. Test quality was good.
		Continuous monitors	CO was still off line. Backup unit was ordered but had not arrived. Remaining data quality was good.
5/12	8	Inlet-North	Test started at 0840 hours and ran for 462 minutes. No problems were encountered. Test quality was good.
		Inlet-South	Test started at 0837 hours and ran for 528 minutes. No problems were encountered. Test quality was good.
		Outlet-North	Test started at 1040 hours and ran for 450 minutes. No problems were encountered. Test quality was good.
		Outlet-South	Test started at 0854 hours and ran for 450 minutes. No problems were encountered. Test quality was good.
		Hi Volume Sampler	Test started at 1243 hours and was stopped at 1840 hours. Test quality was good.
		Continuous monitors	No CO data was being monitored. Remaining data was good.
5/13	9	Inlet-North	Test started at 0833 hours and ran for 472 minutes. Boiler was down at conclusion of test for grate cleaning. Test quality was good.
		Inlet-South	Test started at 0815 hours and ran for 528 minutes. Test quality was good.
		Outlet-North	Test started at 0832 hours and ran for 450 minutes. Test quality was good.
		Outlet-South	Test started at 0818 hours and ran for 450 minutes. Test quality was good.
		Hi Volume Sampler	Test started at 0912 hours and was stopped at 1820 hours. Test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling locations	Test comments
5/13	9	Continuous monitors	CO was still off line, however remaining data was good.
5/15	10	Inlet-North	Test started at 0805 hours and ran for 464 minutes. Test quality was good.
		Inlet-South	Test started at 0803 hours and ran for 528 minutes. Test quality was good.
		Outlet-North	Test started at 0840 hours and ran for 450 minutes. Probe was found with a cracked tip. Based on 8.9% moisture vs. 12% moisture for the other tests, it seems only the last 10 pts. were traversed with broken probe. Test quality was fair.
		Outlet-South	Test started at 0820 hours and ran for 450 minutes. Test quality was good.
		Hi Volume Sampler	Test started at 1110 hours and was stopped at 1840 hours. Test quality was good.
		Continuous monitors	New CO analyzer came on line. Test quality was good.
5/16	11	Inlet-North	Test started at 0830 hours and ran for 462 minutes. No problems were encountered. Test quality was good.
		Inlet-South	Test started at 0924 hours and ran for 528 minutes. Final leak rate was not obtained, however the data was corrected by subtracting out the last two unknown points (35 cu. ft.). This caused little effect on the final outcome of the test. Test quality was good.
		Outlet-North	Test started at 0808 hours and ran for 450 minutes. No problems were encountered. Test quality was good.
		Outlet-South	Test started at 0828 hours and ran for 450 minutes. No problems were encountered. Test quality was good.

TABLE 2-1. (Continued)

Date (1980)	Test No.	Sampling locations	Test comments
5/16	11	Hi Volume Sampler	Test started at 0806 hours and was stopped at 1910 hours. Test quality was good.
		Continuous monitors	THC data reading was high (300 ppm) between 1000 hours and 1030 hours due to temporary shortage of garbage in chute.
5/17	12	Inlet-North and South	Test started at 0928 hours and ran for 500 minutes. QA test was performed simultaneously at Inlets on the north and the south. Test quality was good.
		Outlet-North and South	Test started at 0815 hours and ran for 250 minutes. This was the first day for the cadmium test. Test quality was good.
		Blank	Test started at 0820 hours and ran for one hour at 250°F. Test quality was good.
		Hi Volume Sampler	Test started at 1028 hours and was stopped at 1835 hours. Test quality was good.
		Continuous monitors	No problems were encountered. Test quality was good.
5/18	13	Outlet-North	Test started at 0820 hours and ran for 250 minutes. For the cadmium test the outlet was only tested. No problems were encountered. Test quality was good.
		Hi Volume Sampler	Test started at 0800 hours and was stopped at 1305 hours. Test quality was good.
		Continuous monitors	The outlet was only tested and no THC data was recorded since it was not required for the cadmium test. Test quality was good.
5/19	14	Outlet-North and South	Test started at 0810 hours and ran for 250 minutes. No problems were encountered. Test quality was good.
		Hi Volume Sampler	Test started at 0800 hours and was stopped at 1300. Test quality was good.
		Continuous monitors	No problems were encountered. Test quality was good.

TABLE 2-2. DAILY DATA SUMMARY

Date (1980)	Test No.	Sampling Location		Sample Volume SDCF	Sample Volume Nm^3	Gas Composition① O_2 %	CO_2 %	CO ppm	THC ppm	Stack Temperature °F	Molecular Weight	Moisture %	Velocity ft/sec	Gas Flow ACFM	Gas Flow DSCFM	Isokinetic Rate %
5-4	1	Inlet	North	256.837	7.27	11.2	7.4	172②	<2	459.47	28.28	11.68	20.17	50332.218	24952.931	90.82
			South	135.203	3.83	11.2	7.4	172	<2	444.88	28.52	9.57	21.27	61074.783	31543.243	79.24
		Outlet	North	317.860	9.00	11.3	7.7	156	<2	432.76	28.33	11.56	38.40	49138.650	25074.591	94.61
			South	324.144	9.20	11.3	7.7	156	<2	451.27	28.41	10.87	39.33	53102.716	26764.698	97.96
5-6	2	Inlet	North	408.462	11.57	9.6	10.1	159	<2	459.04	28.53	12.24	20.62	51452.653	25077.734	96.25
			South	379.181	10.74	9.6	10.1	159	<2	445.78	28.56	12.03	18.42	52895.304	26217.876	98.32
		Outlet	North	418.430	11.85	10.4	9.5	171	<2	442.00	28.45	12.47	38.21	51588.415	25528.869	98.85
			South	457.890	12.97	10.4	9.5	171	<2	451.04	29.58	2.95	40.60	54822.866	29782.359	93.23
5-7	3	Inlet	North	324.361	9.19	9.4	9.8	185	<2	445.56	28.34	13.43	19.90	49665.946	24406.919	96.17
			South	400.656	11.34	9.4	9.8	185	<2	431.46	28.36	13.26	21.23	61306.230	30518.360	97.71
		Outlet	North	403.319	11.42	9.4	9.7	189	<2	459.04	28.39	12.86	36.70	49556.634	24144.057	100.75
			South	407.071	11.53	9.4	9.7	189	<2	457.78	28.41	12.75	38.87	52477.089	25634.970	96.29
5-8	4	Inlet	North	331.522	9.39	9.9	9.6	142	<2	445.36	28.57	11.27	19.34	48268.522	24418.162	100.22
			South	370.826	10.50	9.9	9.5	142	<2	460.60	28.50	11.86	19.96	57305.160	28349.017	97.28
		Outlet	North	427.497	12.11	10.4	8.9	169	<2	464.20	28.82	8.60	38.39	51835.952	26693.503	96.59
			South	457.496	12.96	10.4	8.9	169	<2	464.32	28.47	11.60	41.69	56292.592	27732.316	100.04
5-9	5	Inlet	North	342.697	9.77	7.9	10.5	61	<2	423.77	28.30	14.14	17.71	44193.534	22187.466	99.85
			South	367.809	10.42	7.9	10.5	61	<2	460.80	28.20	14.94	17.31	49706.823	23679.562	101.90
		Outlet	North	371.561	10.52	8.1	10.7	59	<2	449.64	28.17	15.46	32.99	44544.600	21337.899	105.57
			South	383.750	10.87	8.1	10.7	59	<2	437.76	28.24	14.89	32.48	43856.604	21431.687	107.99
5-10	6	Inlet	North	320.564	9.08	8.8	10.3	③	<2	452.59	28.37	13.62	18.12	45257.690	21770.430	108.82
			South	347.607	9.84	8.8	10.3		<2	457.63	28.34	13.83	17.86	51267.447	24476.323	105.61
		Outlet	North	367.971	10.42	9.4	9.7		<2	448.92	28.50	11.84	35.43	47837.327	23572.100	98.61
			South	412.061	11.67	9.4	9.7		<2	452.28	28.33	13.40	39.50	53339.650	25751.431	96.51
5-11	7	Inlet	North	344.803	9.76	9.8	9.0	③	<2	463.29	28.19	13.86	19.12	47760.487	22877.439	100.86
			South	378.495	10.72	9.8	9.0		<2	462.48	28.15	14.24	18.51	53212.640	25400.444	100.82
		Outlet	North④	299.617	8.49	9.8	9.5		<2	462.53	28.37	12.91	38.09	42103.978	20345.095	99.20
			South④	459.634	13.02	9.8	9.5		<2	447.47	28.30	13.52	38.13	61760.300	30126.657	102.22
5-12	8	Inlet	North	316.551	8.96	8.7	9.7	③	<2	456.24	28.40	12.57	17.58	43898.069	21492.745	98.95
			South	373.034	10.56	8.7	9.7		<2	468.33	28.38	12.79	19.11	54933.801	26479.880	94.93
		Outlet	North	376.483	10.66	10.4	9.0		<2	442.84	28.41	12.21	36.73	49586.850	24703.730	102.67
			South	391.172	11.08	10.4	9.0		<2	452.88	28.42	12.08	39.17	52884.900	26093.924	100.42

TABLE 2-2. (Continued)

Date (1980)	Test No.	Sampling Location		Sample Volume SDCF	Sample Volume Nm^3	Gas Composition (1) O_2 %	CO_2 %	CO ppm	THC ppm	Stack Temperature °F	Molecular Weight	Moisture %	Velocity ft/sec	Gas Flow ACFM	Gas Flow DSCFM	Isokinetic Rate %
5-13	9	Inlet	North	308.728	8.74	9.7	9.6	(3)	<2	465.61	28.19	14.57	16.42	41015.923	19294.229	105.23
			South	364.161	10.31	9.7	9.6		<2	468.65	28.19	14.52	17.82	51223.782	24032.783	102.11
		Outlet	North	366.284	10.37	9.1	9.8		<2	457.16	28.25	14.10	36.85	49744.800	23723.700	104.01
			South	388.729	11.01	9.1	9.8		<2	453.62	28.20	14.54	39.39	53180.550	25332.204	102.82
5-15	10	Inlet	North	338.450	9.59	10.2	9.4	111 (5)	<2	465.43	28.29	13.60	16.05	45076.682	21919.803	102.87
			South	376.856	10.67	10.2	9.4	111	<2	456.88	28.27	13.75	17.67	50795.373	24835.199	102.67
		Outlet	North	377.441	10.69	9.6	9.7	98	<2	459.58	28.88	8.89	35.47	47889.900	24697.316	102.40
			South	396.275	11.22	9.6	9.7	98	<2	463.68	28.24	14.22	38.49	51958.800	25113.412	106.30
5-16	11	Inlet	North	353.833	10.02	11.1	8.5	88 (5)	<2	466.32	28.40	11.15	18.79	46930.228	23389.304	101.23
			South	357.302	10.12	11.1	8.5	88	<2	467.67	28.42	11.69	18.22	52360.297	25822.708	93.06
		Outlet	North	404.610	11.46	11.8	7.9	98	<2	466.72	28.36	11.78	38.93	58118.450	29188.890	104.02
			South	416.675	11.80	11.8	7.9	98	<2	460.24	28.30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5-17	12	Inlet (6)	North	324.920	9.20	10.3	10.0	80	<2	474.80	28.27	13.47	17.26	43045.650	20524.938	97.56
			South	331.750	9.40	10.3	10.0	80	<2	475.00	28.37	13.70	16.86	48387.834	23013.917	102.20
		Outlet (6)		218.810	6.20	10.7	9.0	84	<2	461.00	28.16	14.38	39.27	106036.090	51352.600	103.01
5-18	13	Inlet	North South	(7)												
		Outlet		219.36	6.20	10.7	9.2	102	(8)	463;00	28.25	13.91	44.37	119798.300	57360.170	92.45
5-19	14	Inlet	North South	(7)												
		Outlet		240.61	6.81	12.7	7.2	304	(8)	465.60	28.36	11.65	44.53	120233.700	59137.720	98.36

(1) Test period average
(2) High due to excessive instrument drift
(3) Analyzer taken off line (see (2))
(4) Due to excessive leak rate in the north train, 60% of sample was collected with south train, 40% with the north
(5) Results ± 10 ppm due to drift
(6) *Inlet QA Test, Outlet 1st day Cadmium Test*
(7) Inlet sample not required for Cadmium Test
(8) THC data not required for Cadmium Test

These three parameters were also monitored by means of integrating counters. Each numerical reading multipled by 150 yielded the amount of steam in pounds, the amount of feedwater in pounds, or the amount of combustion air in cubic feet. These numbers have been included in the tables in Appendix D in terms of 1000's of pounds or 1000's of cubic feet. The differences of these numbers were also calculated on an hourly basis to determine flow rates from these quantities and are listed under "digital integrator" in Appendix D.

Each integrator reading is assumed to have been taken at the end of the hour in question. For instance, the 5 PM reading represents the hour ending at 5 PM, as opposed to the hour beginning at 5 PM. This was necessary in order to maintain consistency, especially in the case of the integrator differences. The difference between the 5 PM integrator reading and the 4 PM integrator reading represents the flow occuring between 4 PM and 5 PM, and therefore is a 5 PM flow measurement, according to this end-of-the-hour convention. Further, the digital counters recycle occasionally. Since the counters have six digits, the largest possible number is 999,999 x 150 ÷ 1000 or 150,000. It must also be noted that even a 5 minute delay in taking a reading introduces a substantial error in the hourly value. Finally, these integrator values were the only readings not routinely taken by plant personnel on a 24 hour basis. As a result, large gaps exist in this data. Averages were taken over these periods whenever possible.

The steam flow rate was also recorded on a continuous basis. This was done by an ink pen recorder located outside the control room. The recorder plotted instantaneous steam flow values on graph paper. Hourly values were recorded from these sheets, and are presented in Appendix D under the heading "disc recorder". Although this instrument may have been very accurate, the operators were not always careful at aligning the paper discs. The erratic nature of steam production at the plant was easily observable from these plots. Oscillations of an amplitude of 30,000 lbs/hr and a frequency of 6-10 cycles per hour seemed typical. A sample plot is provided in Appendix D.

Steam pressure, combustion air temperature, % oxygen, I.D. fan pressure, F.D. fan pressure, furnace draft, and furnace temperature were all noted from pointer gauges in the control room. The combustion air temperature was actually a measurement of the flue gas leaving the boiler and entering the economizer. The sensor for % oxygen was located on the ESP side of the economizer. It must also be noted that the furnace draft and I.D. fan meters were actually measuring a vacuum.

Other information contained in the daily process data tables includes times of soot blowing, fuel input to Boiler No. 2, down time on Boiler No. 2, a daily barometric pressure and miscellaneous comments concerning the boiler operation. According to plant procedure, soot blowing should have always occurred at 3 AM, 11 AM, and 7 PM every day, but deviations from this schedule were often observed. Fuel input is usually expressed as crane loads, or charges of refuse. In only one instance was natural gas burned to start up the boiler. The amount of gas burned is reported in cubic feet, but the actual measurement involved reading a numeric counter and multiplying by 3.5. Down time is expressed as lost burning time, and was available by consulting plant records. The barometric pressure was obtained once a day from nearby Midway airport. Comments listed on the process sheets (refer to Appendix D) were derived from the operator's log book or by discussing plant conditions first-hand with the operators and firemen on duty.

2.2.1 24-Hour Data

The means and standard deviations of the parameters included in the daily process sheets were calculated on a 24-hour basis for every day of testing. This information has been presented in Table 2-3. On some days Boiler No. 2 did not operate for the entire 24 hour period. For these days, data was not available on a 24 hour basis, consequently values have been calculated based on available information. Also, since the integrator differences were often averaged over long periods of time, it did not seem appropriate to provide standard deviations in these instances.

A qualitative observation from Table 2-3 indicates that the plant operation is very uniform over a time average of one day. According to the daily process sheets, no strong diurnal variations occurred. This is not to say that large variations did not exist. Shorter averaging times (less

TABLE 2-3. 24 HOUR PROCESS DATA FOR THE CHICAGO NORTHWEST MUNICIPAL INCINERATOR, UNIT NO. 2

Date	5-4-80		5-6-80		5-7-80		5-8-80		5-9-80		5-10-80		5-11-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
Steam Flow Rate														
Disc Recorder (lbs/hr)	104000*	11389.3	91000*	30891.2	103000	8040.5	103000	13028.3	102000	17545.0	100000	10309.6	100000	11262.9
Chart Recorder (lbs/hr)	100000*	9350.6	102000*	11827.0	100000	9949.0	103000	11089.0	106000	8901.0	104000	14057.0	104000	14320.0
Digital Integrator (lbs/hr)	100000*	NA	91000*	NA	102000	NA	99000	NA	103000	NA	103000	NA	102000	NA
Steam Pressure (psig)	203*	6.0	270*	59.4	284	4.9	284	6.0	284	7.6	284	6.7	285	6.0
Feedwater Flow Rate														
Chart Recorder (lbs/hr)	98000*	9486.0	104000*	7935.6	103000	12740.4	98000	14604.7	103000	10980.6	101000	12121.4	102000	13640.0
Digital Integrator (lbs/hr)	92000*	NA	86000*	NA	99000*	NA	98000	NA	102000	NA	102000	NA	100000	NA
Feedwater Temperature (°F)	222*	3.0	222*	3.2	220	1.0	220	0.6	220	0.0	221	1.4	220	0.0
Combustion Air Flow Rate														
Chart Recorder (ft³/hr)	82000*	3810.4	79000*	5369.7	77000	4506.0	81000	5070.5	77000	7404.0	79000	7079.9	77000	6685.6
Digital Integrator (ft³/hr)	75000*	NA	74000*	NA	70000	NA	73000	NA	70000	NA	72000	NA	71000	NA
Combustion Air Temperature (°F)	718*	21.7	658*	126.3	681	30.6	642	26.7	662	27.3	678	20.1	675	30.9
Percent Oxygen	14.7*	2.73	12.0*	5.0	10.5	1.56	12.6	1.6	11.2	2.55	12.0	1.61	11.1	2.10
I.D. Fans Pressure (in. H_2O)	3.0*	0.20	2.6*	0.30	2.4	0.25	2.8	0.33	2.5	0.56	2.5	0.29	2.5	0.20
F.D. Fans Pressure (in. H_2O)	13.1*	0.70	14.2*	0.94	13.9	0.06	14.5	0.64	14.0	0.61	14.2	0.63	14.6	0.50
Furnace Draft (in. H_2O)	0.35*	0.07	0.24*	0.09	0.21	0.080	0.30	0.080	0.17	0.13	0.21	0.076	0.13	0.072
Furnace Temperature (°F)	1170*	43.2	1096*	306.0	1209	71.0	1187	72.7	1189	107.0	1184	77.3	1203	106.4

Date	5-12-80		5-13-80		5-15-80		5-16-80		5-17-80		5-18-80		5-19-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
Steam Flow Rate														
Disc Recorder (lbs/hr)	94000	10498.6	95000*	14826.7	96000	9837.0	97000	9719.9	103000*	9330.3	102000*	13950.0	92000	10000.6
Chart Recorder (lbs/hr)	104000	14275.5	101000*	13069.7	102000*	9367.3	98000	8255.0	102000	9465.0	105000	13576.9	90000	19195.7
Digital Integrator (lbs/hr)	98000	NA	100000*	NA	97000	NA	97000	NA	100000	NA	99000	NA	93000	NA
Steam Pressure (psig)	283	4.4	282*	7.5	283	6.1	282	7.0	285*	4.9	284	4.7	277	5.3
Feedwater Flow Rate														
Chart Recorder (lbs/hr)	102000	13600.4	98000*	15224.4	96000*	9705.0	93000	9836.3	99000	12032.3	103000	14676.0	87000	13947.9
Digital Integrator (lbs/hr)	97000	NA	99000*	NA	100000	NA	95000	NA	102000*	NA	86000	NA	93000	NA
Feedwater Temperature (°F)	221	2.1	220*	0.5	221	0.9	220	0.6	221	0.93	221	0.9	220	0.76
Combustion Air Flow Rate														
Chart Recorder (ft³/hr)	77000	6685.6	79000*	4400.0	78000*	5340.0	82000	5753.4	82000	5493.7	80000	4316.9	81000	9229.0
Digital Integrator (ft³/hr)	69000	NA	70000*	NA	72000	NA	74000	NA	73000	NA	72000	NA	79000	NA
Combustion Air Temperature (°F)	653	22.4	665*	49.7	651*	21.5	660	35.0	666	21.0	653	25.0	675	36.2
Percent Oxygen	11.1	1.60	11.7*	2.10	11.1	1.35	13.5	2.13	10.4	1.12	10.6	1.50	12.6	1.20
I.D. Fans Pressure (in. H_2O)	2.3	0.27	2.4*	0.24	2.4	0.42	2.8	0.30	2.6	0.16	2.7	0.11	3.0	0.34
F.D. Fans Pressure (in. H_2O)	13.4	2.10	14.6*	0.50	14.1	0.32	14.0	0.36	14.0	0.42	14.1	0.37	14.2	0.30
Furnace Draft (in. H_2O)	0.17	0.083	0.20*	0.090	0.20	0.093	0.25	0.067	0.25	0.086	0.29	0.072	0.30	0.087
Furnace Temperature (°F)	1160	90.9	1180*	100.7	1170	65.5	1112	80.0	1204	78.6	1207	80.6	1061	91.0

* Does not represent full 24-hour period   NA - Not Appropriate

than an hour) would indicate large swings, and this is reflected in the large standard deviations for steam production in Table 2-3. This was due to the intermittent nature of fuel feed to the boiler. However, these production swings did not depend on time of day or day of week. Consequently, it was possible to calculate means and standard deviations over a large number of test days. This has been done for all of the test days (refer to Table 2-4). An examination of data in Table 2-4 indicates that the standard deviations are smaller than most of the standard deviations in Table 2-3. Although variations may be expected to decrease over longer averaging times, this would not be true if certain days had significantly different modes of operation. The aforementioned therefore indicates that the Chicago Northwest Incineration facility operates in essentially the same mode 24 hours a day, 7 days a week, although instantaneous swings in steam production do occur continuously over short time intervals (less than one hour).

2.2.2 Test Duration Data

Means and standard deviations have been calculated on a test duration basis for all of the test days. This information has been provided in Table 2-5. The discussion on diurnal variations pertaining to the 24-hour data also pertains here, although the standard deviations should, in general, be smaller due to the shorter period of time being considered. An examination of the data in Table 2-5 bears this out.

None of the data in Table 2-5 appears particularly anomalous. No significant variation in steam production occurred from day to day indicating a rather consistant fuel feed rate during the duration of the tests. Some days exhibited wider variations as reflected by higher standard deviations, particularly on the 19th of May. The variation of feed water flow does not corelate well with the variation in steam production. The operating parameters seemed to fluctuate rather independently, without any pronounced impact on other aspects of plant operation.

TABLE 2-4. MEANS OF THE MEANS FOR 24-HOUR PROCESS DATA, ALL TEST DAYS, CHICAGO NORTHWEST MUNICIPAL INCINERATOR.

Parameter	Mean	σ
Steam Flow Rate (lbs/hr)		
Disc Recorder	99,000	
Chart Recorder	103,000	4,516.8
Digital Integrator	99,000	3,577.0
Steam Pressure (psig)	282	4.02
Feedwater Flow Rate (lbs/hr)		
Chart Recorder	99,000	4,822.7
Digital Integrator	97,000	5,445.5
Feedwater Temperature (°F)	221	0.7
Combustion Air Flow Rate (ft^3/hr)		
Chart Recorder	79,000	2,016.4
Digital Integrator	72,000	2,593.3
Combustion Air Temperature (°F)	663	21.2
% Oxygen	11.8	1.23
I.D. Fans Pressure (inches H_2O)	2.6	0.22
F.D. Fans Pressure (inches H_2O)	14.1	0.38
Furnace Draft (inches H_2O)	0.23	.061
Furnace Temperature (°F)	1,160	41.5

TABLE 2-5. TEST DURATION PROCESS DATA FOR THE CHICAGO NORTHWEST MUNICIPAL INCINERATOR, UNIT NO. 2

Date	5-4-80		5-6-80		5-7-80		5-8-80		5-9-80		5-10-80		5-11-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
Steam Flow Rate														
Disc Recorder (lbs/hr)	96000	10446.3	98000	17676.4	107000	6356.1	110000	12509.6	108000	8165.6	103000	12202.5	99000	11121.8
Chart Recorder (lbs/hr)	103000	11319.2	104000	7146.1	111000	9342.0	111000	12870.7	113000	3500.0	112000	16465.0	109000	12381.0
Digital Integrator (lbs/hr)	91000	NA	104000	NA	100000	NA	104000	NA	113000	NA	104000	NA	105000	NA
Steam Pressure (psig)	286	7.4	286	7.0	288	4.1	289	6.4	290	8.0	288	6.3	289	5.5
Feedwater Flow Rate														
Chart Recorder (lbs/hr)	95000	7559.3	104000	7106.3	108000	8738.6	95000	24494.9	114000	4106.6	105000	10409.6	107000	11643.2
Digital Integrator (lbs/hr)	98000	NA	100000	NA	103000*	NA	102000	NA	110000	NA	105000	NA	105000	NA
Feedwater Temperature (°F)	223	3.6	221	2.1	220	1.5	220	0	220	0	221	1.3	221	1.0
Combustion Air Flow Rate														
Chart Recorder (ft^3/hr)	82000	3720.1	79000	4743.4	77000	4101.0	80000	3503.2	72000	3492.1	79000	8350.6	76000	5090.2
Digital Integrator (ft^3/hr)	71000	NA	74000	NA	69000	NA	73000	NA	67000	NA	70000	NA	69000	NA
Combustion Air Temperature (°F)	724	26.2	701	31.4	670	33.2	646	29.1	676	28.5	671	27.1	692	21.6
Percent Oxygen	16.0	2.97	10.1	1.34	10.3	1.79	11.5	1.00	9.2	1.46	12.0	2.20	9.8	1.44
I.D. Fans Pressure (in. H_2O)	3.0	0.31	2.6	0.23	2.4	0.26	2.0	0.22	2.1	0.42	2.2	0.23	2.4	0.20
F.D. Fans Pressure (in. H_2O)	12.7	0.46	10.6	0.28	13.9	0.05	10.6	0.56	13.6	0.08	13.8	0.57	14.7	0.37
Furnace Draft (in. H_2O)	0.30	0.050	0.24	0.089	0.25	0.080	0.30	0.100	0.12	0.080	0.19	0.061	0.14	0.057
Furnace Temperature (°F)	1169	85.8	1205	59.9	1225	52.4	1189	71.0	1290	67.9	1205	100.6	1264	80.5

Date	5-12-80		5-13-80		5-15-80		5-16-80		5-17-80		5-18-80		5-19-80	
	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
Steam Flow Rate														
Disc Recorder (lbs/hr)	97000*	11006.0	96000	13705.7	95000	11274.3	95000	10740.8	103000	8533.4	107000	10604.6	79000	23741.7
Chart Recorder (lbs/hr)	105000	10922.0	101000	10319.4	94000*	33611.3	99000	7163.6	106000	6795.2	100000	3206.6	82000	30750.3
Digital Integrator (lbs/hr)	105000	NA	100000*	NA	100000	NA	92000	NA	94000	NA	104000	NA	71000	NA
Steam Pressure (psig)	285	5.8	284	6.8	281	3.5	287	3.3	289	2.9	290	2.9	281	2.5
Feedwater Flow Rate														
Chart Recorder (lbs/hr)	103000	10443.5	102000	6687.5	90000*	8292.6	93000	10972.1	104000	8266.4	108000	5400.0	80000	17895.5
Digital Integrator (lbs/hr)	103000	NA	106000*	NA	104000	NA	93000	NA	94000*	NA	117000	NA	73000	NA
Feedwater Temperature (°F)	222	3.1	220	0.9	220	0	220	0	222	0.9	221	1.2	222	1.0
Combustion Air Flow Rate														
Chart Recorder (ft^3/hr)	76000	5106.5	77000*	5669.5	77000*	3374.7	80000	1043.0	81000	4303.5	80000	0	61000	2500.0
Digital Integrator (ft^3/hr)	71000	NA	68000*	NA	70000	NA	72000	NA	67000	NA	73000	NA	69000	NA
Combustion Air Temperature (°F)	653	18.9	672	30.0	657	23.1	647	28.7	671	25.0	690	0.2	645	60.1
Percent Oxygen	10.5	1.03	11.1	1.42	11.2	1.32	10.8	1.01	9.0	1.25	10.9	1.64	13.1	1.16
I.D. Fans Pressure (in. H_2O)	2.3	0.35	2.3	0.30	2.3	0.21	2.3	0.20	2.6	0.15	2.5	0.10	2.0	0.30
F.D. Fans Pressure (in. H_2O)	14.2	0.47	15.0	0.54	10.2	0.46	13.9	0.19	14.0	0.27	14.2	0.19	14.3	0.20
Furnace Draft (in. H_2O)	0.21	0.099	0.10	0.070	0.14	0.080	0.23	0.062	0.24	0.060	0.30	0.042	0.34	0.111
Furnace Temperature (°F)	1195	121.2	1188	90.1	1180	73.0	1129	64.7	1238	62.6	1269	37.5	1019	134.1

* Some data points are missing   NA = Not Appropriate

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2.2.3 Weekly Refuse and Residue Inventory

All refuse and residue hauling trucks entering and leaving the incinerator plant were carefully weighed. This facilitates the accurate characterization of overall inputs and outputs. However, there is no accurate way of proportioning these materials between specific boilers for a given period of time. Any attempt to determine the fuel burned or ash discharged from Boiler No. 2 can only be an approximation.

Chicago Northwest Incinerator maintains inventory sheets listing inputs and outputs from the facility on a weekly basis. Relevant data from these sheets have been reproduced in Table 2-6. The weight of refuse received was measured on scales before and after the refuse trucks released their loads. The volume of refuse received was determined by multiplying the number of truck loads by the volume of each truck (19.5 cubic yards). Density of the refuse was estimated using these two measurements, and is therefore the density of refuse inside the trucks. In order to quantify the amount of refuse burned, the number of loads, or charges, handled by the grab bucket cranes were noted for each boiler. A total number of charges are listed in Table 2-7. The charges delivered to Boiler No. 2 are given in the daily process data sheets on a shift basis. These are provided in Appendix D.

To approximate the amount of refuse burned in Boiler No. 2, it is necessary to determine an average weight per charge, since the number of charges fed into this boiler are known (Appendix D). The method for doing this, however, is not entirely obvious. When refuse trucks enter the plant, they discharge their contents into a large storage pit. Although the weight of refuse added to the pit is well characterized for each weekly period, the carry-over of material from week to week cannot be accurately measured. Furthermore, this carry-over is quite variable over the length of time being considered. It is also significant, as the pit is sometimes over half full, corresponding to roughly 5000 cubic yards of refuse. It is necessary to quantify the carry-over in terms of weight, so that the total weight of refuse burned, and hence, the average weight per charge, can be approximated. This can be done by 3 different methods.

TABLE 2-6. WEEKLY INVENTORIES OF REFUSE AND RESIDUE AT THE CHICAGO NORTHWEST MUNICIPAL INCINERATOR (ALL BOILERS).

	4/28/80 to 5/4/80	5/5/80 to 5/11/80	5/12/80 to 5/18/80	5/19/80 to 5/25/80
Refuse Received				
By weight (tons)	6,746.65	9,152.34	7,902.34	8,720.21
By volume (cubic yards)	24,490	29,618	26,561	28,778
Density (lbs/yd^3)	551	618	595	606
Storage Pit Condition				
At beginning of week (% full)	84	65	61	42
At end of week (% full)	65	61	42	42
Refuse Consumed				
# charges burned	5,205	5,710	5,952	4,714
Average weight per charge (lbs)	2,771	3,240	2,812	3,700
Total weight (tons)	7,212	9,250	8,367	8,720
Total volume (cubic yards)	28,562	36,634	33,138	34,535
Residue				
Fine ash fraction (tons)	2,511	2,500	1,815	2,904
Fine ash fraction (cubic yards)	3,100	3,086	2,240	3,585
Metal fraction (tons)	949	750	1,514	629
Metal fraction (cubic yards)	5,423	4,286	18,651	3,594
Total ash (tons)	3,460	3,250	3,329	3,533
Total ash (cubic yards)	8,523	7,372	10,891	7,179
Volume Reduction thru incineration	70%	80%	67%	79%
Weight Reduction thru incineration	52%	65%	60%	60%

TABLE 2-7. CHARGES FED TO EACH BOILER ON A SHIFT BASIS CHICAGO NORTHWEST INCINERATION FACILITY

Date,	Shift	Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
4-28,	2nd	88	98	101	--	287
	3rd	101	99	100	--	300
4-29,	1st	101	100	101	--	302
	2nd	27	94	89	--	210
	3rd	89	101	97	--	287
4-30,	1st	35	90	94	--	219
	2nd	--	94	99	--	193
	3rd	78	101	94	--	273
5-1,	1st	75	94	95	--	264
	2nd	38	49	45	--	132
	3rd	94	98	93	--	285
5-2,	1st	101	100	98	--	299
	2nd	101	98	95	--	294
	3rd	97	101	96	--	294
5-3,	1st	33	100	102	--	235
	2nd	27	102	96	--	225
	3rd	62	99	97	--	258
5-4,	1st	20	97	98	--	215
	2nd	94	96	93	--	283
	3rd	36	12	101	--	149
5-5,	1st	101	--	100	--	201
Total for week		1398	1823	1984	0	5205

TABLE 2-7. (Continued)

Date, Shift		Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
5-5,	2nd	106	--	101	--	207
	3rd	83	--	86	--	169
5-6,	1st	102	--	103	--	205
	2nd	104	68	107	--	279
	3rd	70	112	111	--	293
5-7,	1st	37	99	98	--	234
	2nd	14	84	83	--	181
	3rd	101	100	97	--	298
5-8,	1st	77	81	101	--	259
	2nd	102	101	101	--	304
	3rd	102	100	98	--	300
5-9,	1st	101	100	100	--	301
	2nd	101	98	100	--	299
	3rd	101	100	101	--	302
5-10,	1st	98	99	101	--	298
	2nd	52	101	100	--	253
	3rd	101	100	102	--	303
5-11,	1st	103	102	103	--	308
	2nd	102	101	101	--	304
	3rd	99	105	102	--	306
5-12,	1st	104	103	100	--	307
Total for week		1860	1754	2096	0	5710

TABLE 2-7. (Continued)

Date, Shift	Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
5-12, 2nd	39	99	98	--	236
3rd	97	99	99	--	295
5-13, 1st	102	100	100	--	302
2nd	104	100	104	--	308
3rd	98	60	103	--	261
5-14, 1st	100	--	100	--	200
2nd	98	--	96	--	194
3rd	94	96	102	--	292
5-15, 1st	106	104	110	--	320
2nd	105	106	107	--	318
3rd	107	108	106	--	321
5-16, 1st	108	106	110	--	324
2nd	38	97	85	--	220
3rd	112	110	108	--	330
5-17, 1st	110	112	112	--	334
2nd	98	97	98	--	293
3rd	118	114	108	--	340
5-18, 1st	106	108	109	--	323
2nd	75	104	105	--	284
3rd	--	118	124	--	242
5-19, 1st	--	105	110	--	215
Total for week	1815	1943	2194	0	5952

TABLE 2-7. (Continued

Date, Shift	Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
5-19, 2nd	--	110	114	--	224
3rd	103	105	105	--	313
5-20, 1st	104	104	106	--	314
2nd	120	118	100	--	338
3rd	--	110	108	--	218
5-21, 1st	--	100	103	--	203
2nd	--	106	104	--	210
3rd	68	90	88	--	246
5-22, 1st	21	80	82	--	183
2nd	--	105	107	--	212
3rd	--	100	100	--	200
5-23, 1st	--	107	104	--	211
2nd	--	107	104	--	211
3rd	--	102	100	--	202
5-24, 1st	--	98	92	--	190
2nd	--	105	107	--	212
3rd	--	94	101	--	195
5-25, 1st	--	101	104	--	205
2nd	--	105	108	--	213
3rd	--	107	102	--	209
5-26, 1st	--	105	100	--	205
Total for week	416	2159	2139	0	4714

The first method involves using visual measurements of the pit volume taken at the end of each week. This "pit estimate" can then be used in association with the density of the incoming garbage to approximate the weight of refuse in the pit. Then the average weight per charge can be determined by the following equation:

Average wt per charge = (pit estimate for previous week - pit estimate + refuse delivered) ÷ total number of charges

All terms in parenthesis must be expressed as weights. This method however has a drawback in that the density in the pit is probably not the same as the density inside the refuse trucks, since the refuse inside the trucks is compacted and is liable to expand somewhat as the trucks are unloaded.

The second method is essentially the same as the first, but a different assumption is made for pit density. It seems likely that the level of compression would have a more pronounced effect upon the refuse density than the actual characteristics of the refuse. Since the compaction inside the pit is always similar, one would also expect the density in the pit to be reasonably constant. In principle, this is the method applied by the plant personnel, but in practice it is not consistently used by them. It has been found from plant operational experience that a density of 505 lbs/yd^3 is typical of the pit contents. Therefore, this value can be used as an assumed density, and the pit estimates used in the equation as before.

The third method circumvents the problem of pit estimation entirely. Assuming that every charge constitutes a full load of the crane grab bucket, the weight of the charge can then be estimated by multiplying the maximum volume of the bucket by an assumed density. The maximum volume of the bucket is five cubic yards. The primary disadvantage of this method is that any inaccuracy in the density is directly reflected in the average weight per charge.

In this report the second method was chosen as the most appropriate, and the values for total refuse consumed and average weight per charge were tabulated (refer to Table 2-6). A constant, assumed pit density (assumed in method 2) was preferred to a variable "measured" density of method 1.

Furthermore, a "bad" density assumption will cause smaller errors in the first and second cases than in the third case. The second method can be summarized as follows:

$$\text{Volume of refuse in pit} = \frac{\text{pit estimate (\% of total volume)} \times \text{total pit volume}}{100}$$

total pit volume = 9700 yd^3

Weight of refuse in pit = volume of refuse in pit X refuse density in pit

assumed refuse density = 505 lb/yd^3

Weight of refuse incinerated per week = (weight of refuse in pit at beginning of week - weight of refuse in pit at end of week + weight of refuse delivered)

$$\text{Average weight per charge} = \frac{\text{total weight of refuse incinerated}}{\text{total number of charges}}$$

$$\text{Volume of refuse incinerated} = \frac{\text{weight of refuse incinerated}}{\text{assumed refuse density}}$$

The amount of fine ash and metal fractions produced by the incinerator during the test period are listed in Table 2-6 . It should be noted that these are the amounts leaving the plant during this time period, and are not necessarily the same as the ash being produced during this period. Since no account has been taken of any carry-over from week to week, it can only be assumed the carry-over is similar each week. In order to obtain total ash, the metal and fine ash fractions were summed together. The ash volumes were calculated using the following densities:

Density of fine ash fraction = 1620 lbs/yd^3

Density of metal fraction = 350 lb/yd^3

These values are based on previous analyses done by the plant, and have been assumed to be typical. Since all of the combined ash was subjected to a water quench, these weights incorporate a rather large moisture content. However, no better characterization was available. The volume and weight reductions achieved through incineration have been calculated as an indication of how efficiently the boilers were operating.

The ash produced by each boiler can be estimated by either of two ways. First, by estimating the number of hours each boiler was down, the total number of operating hours can be found, and an approximate ash production rate per boiler operating hour can be calculated. All necessary information concerning boiler down hours is presented in Table 2-8. Alternatively, by knowing the number of charges fed to the boilers in a weeks time, an approximate ash production rate per charge of refuse can be calculated. A distribution of charges fed to each boiler on a shift basis is presented in Table 2-7.

2.3 CONTINUOUS MONITORING DATA

Table 2-9 presents daily averages of O_2, CO_2, CO, total hydrocarbons, and ambient temperature as monitored by continuous data logging instrumentation over test duration periods. Hydrocarbon values were consistently lower than the instrument sensitivity of 2 ppm. Most of the data indicates very little variation except for the CO values. The rapid change between May 8, 1980 and May 9, 1980 was due to instrument drift, which places doubt on the validity of the previous data also. The CO analyzer was taken off line, and a new one replaced on May 15, 1980. The high CO value on May 19, was due to unusally high moisture in the fuel on this day. Moreover, the operators did not compensate for the wet feed by changing boiler condition. They were reluctant to change conditions because a new supply of dry feed was anticipated. The high moisture content in the fuel probably inhibited combustion and made burning less efficient. This is reflected in higher O_2, lower CO_2, and higher CO concentration as compared to those on normal operating days.

In Table 2-10, values of percent oxygen measured in the control room and by TRW continuous monitoring instrumentation are compared. The control room readings were observed to be higher than the O_2 analyzer readings on all days except one. This is unusual since the readings should be identical. In any event, the O_2 analyzer should either yield identical or higher readings, because the sample was obtained further downstream and any leakage in the duct would tend to increase the O_2 level of the gas stream. This discrepancy could be due to offset instrument calibrations. It must be noted that the O_2 analyzer indicating lower readings was calibrated (for zero and span) prior to the start of testing and also after the testing concluded for each test day. The control room oxygen analyzer was calibrated once a week.

TABLE 2-8. DOWN TIME EXPRESSED AS LOST FURNACE HOURS FOR THE ENTIRE CHICAGO NORTHWEST INCINERATION FACILITY

Date	Unit No. 1	Unit No. 2	Unit No. 3	Unit No. 4	Total
4-28-80	1	0	0	24	25
4-29-80	8	0	0	24	32
4-30-80	16	1	0	24	41
5-1-80	8	5	6	24	43
5-2-80	0	0	0	24	24
5-3-80	15	0	0	24	39
5-4-80	9	7	0	24	40
Total for week	57	13	6	168	244
5-5-80	0	24	0	24	48
5-6-80	5	12	0	24	41
5-7-80	13	0	0	24	37
5-8-80	2	2	0	24	28
5-9-80	0	0	0	24	24
5-10-80	5	0	0	24	29
5-11-80	0	0	0	24	24
Total for week	25	38	0	168	231
5-12-80	5	0	0	24	29
5-13-80	0	5	0	24	29
5-14-80	0	16	0	24	40
5-15-80	0	0	0	24	24
5-16-80	6	1	1	24	32
5-17-80	0	0	0	24	24
5-18-80	11	0	0	24	35
Total for week	22	22	1	168	213
5-19-80	10	0	0	24	34
5-20-80	8	0	0	24	32
5-21-80	18	0	0	24	42
5-22-80	23	0	0	24	47
5-23-80	24	0	0	24	48
5-24-80	24	0	1	24	49
5-25-80	24	0	0	24	48
Total for week	131	0	1	168	300
Total	235	73	8	672	988

Total possible hours = 2688

Hours lost = 36.8%

TABLE 2-9 . CONTINUOUS MONITORING DATA

Sampling Location	Date (1980)	O_2 (%)		CO_2 (%)		CO (ppm)		THC (ppm)		Ambient Temperature (°C)	
		Mean	σ	Mean	σ	Mean	σ	Mean	σ	Mean	σ
ESP Inlet	5-4	11.2	1.38	7.4	1.07	172	32.76	<2	--	24.7	2.36
ESP Outlet		11.3	0.90	7.7	0.82	156	25.38	<2	--		
Inlet	5-6	9.6	1.43	10.1	1.34	163	20.92	<2	--	15.5	5.45
Outlet		10.4	1.37	9.5	1.20	171	25.04	<2	--		
Inlet	5-7	9.4	1.08	9.8	0.96	185	17.28	<2	--	11.6	1.10
Outlet		9.4	1.78	9.7	1.51	198	44.88	<2	--		
Inlet	5-8	9.9	1.98	9.5	1.81	142	51.32	<2	--	10.0	1.21
Outlet		10.4	1.81	8.7	1.43	169	90.54	<2	--		
Inlet	5-9	7.9	1.09	11.0	0.96	78	38.76	<2	--	14.1	1.98
Outlet		8.1	1.62	10.7	1.37	71	38.66	<2	--		
Inlet	5-10	8.8	1.36	10.3	1.38	Instrument Malfunction		<2	--	18.4	3.56
Outlet		9.4	1.74	9.7	1.54	"	"	<2	--		
Inlet	5-11	9.8	1.18	9.5	1.06	"	"	<2	--	16.7	1.77
Outlet		9.8	1.58	9.5	1.05	"	"	<2	--		
Inlet	5-12	9.6	1.11	9.7	0.89	"	"	<2	--	12.4	0.66
Outlet		10.4	1.69	9.0	1.42	"	"	<2	--		
Inlet	5-13	9.7	1.67	9.6	1.38	"	"	<2	--	11.6	5.60
Outlet		9.6	1.42	9.8	1.14	"	"	<2	--		
Inlet	5-15	10.2	1.51	9.4	1.38	112	36.01	<2	--	15.6	2.71
Outlet		9.6	1.47	9.7	1.18	98	25.70	<2	--		
Inlet	5-16	11.1	1.39	8.5	1.18	88	61.92	<2	--	16.3	1.19
Outlet		11.8	1.32	7.9	1.16	98	75.58	<2	--		
Inlet	5-17	10.3	0.90	10.0	0.75	80	29.61	<2	--	12.8	1.23
Outlet		10.7	1.36	9.0	1.17	84	27.26	<2	--		
Inlet	5-18	Data taken for outlet only						Not Required		12.0	1.34
Outlet		10.7	0.93	9.2	0.85	102	18.71	"	"		
Inlet	5-19	Data taken for outlet only						Not Required		13.0	0.96
Outlet		12.7	1.86	7.2	1.69	304	184.86	"	"		

TABLE 2-10. MEANS OF PERCENT OXYGEN TAKEN BY CONTROL ROOM GAUGE AND O_2 ANALYZER FOR TEST DURATION

Testing Date	Control Room (%)	O_2 Analyzer (ESP inlet) (%)	Difference (Control Room - Analyzer)
5-4	16.4	11.2	5.2
5-6	10.1	9.6	0.5
5-7	10.3	9.4	0.9
5-8	11.5	9.9	1.6
5-9	9.2	7.9	1.3
5-10	12.0	8.8	3.2
5-11	9.8	9.8	0.0
5-12	10.3	9.6	0.7
5-13	11.1	9.7	1.4
5-15	11.2	10.2	1.0
5-16	14.0	11.1	2.9
5-17	9.8	10.3	-0.5
5-18	10.9	10.7	0.2
5-19	13.1	12.7	0.9

3.0 PLANT DESCRIPTION

Chicago Northwest Incinerator is located south of W. Chicago Avenue between the tracks of the Chicago and North-western Railway on the west and Kilbourn Avenue on the east. The principal building of the complex is the Incinerator, a multi-storied structure of reinforced concrete with dimensions of 330 feet by 180 feet and with a maximum height of 79 feet from grade to the main floor. The lowest part of the structure is the floor of the refuse storage pit, approximately 37 feet below grade. To the south of the Incinerator Building and connected to it by the residue conveyors enclosure is the Ash Discharge Building. To the north is the Incinerator Office Building which also houses the maintenance shops. Two stacks each 250 feet in height are located east of the Incinerator Building. The electrostatic precipitators and the induced draft fans are situated between the Incinerator Building and the stacks. The Chicago Northwest Incinerator layout is shown in Figure 3-1. The general characteristics of the Chicago Northwest Incinerator are listed in Table 3-1.

3.1 General Description

Refuse is delivered to the dumping pit of the plant by trucks which back into position above the refuse pit. From the refuse storage pit, crane grapple buckets pick up the refuse and dump it directly into the four furnace feed hoppers. The furnace feed hoppers open into feed chutes which feed automatically onto the stoker grates of the four furnaces.

The grates operate with a reverse-reciprocating action producing an initial downward movement of the refuse and then an upward movement. This combined movement results in a tumbling action. The motion of the grates, an underfire grate jet action, and overfire air jets above the grates all combine to promote highly effective burn-out and complete oxidation of the furnace gases.

The hot furnace gases travel through five boiler passes enroute to the electrostatic precipitator (ESP). Approximately 110,000 pounds of steam is generated by each of the four boilers. In passing through the boiler, the

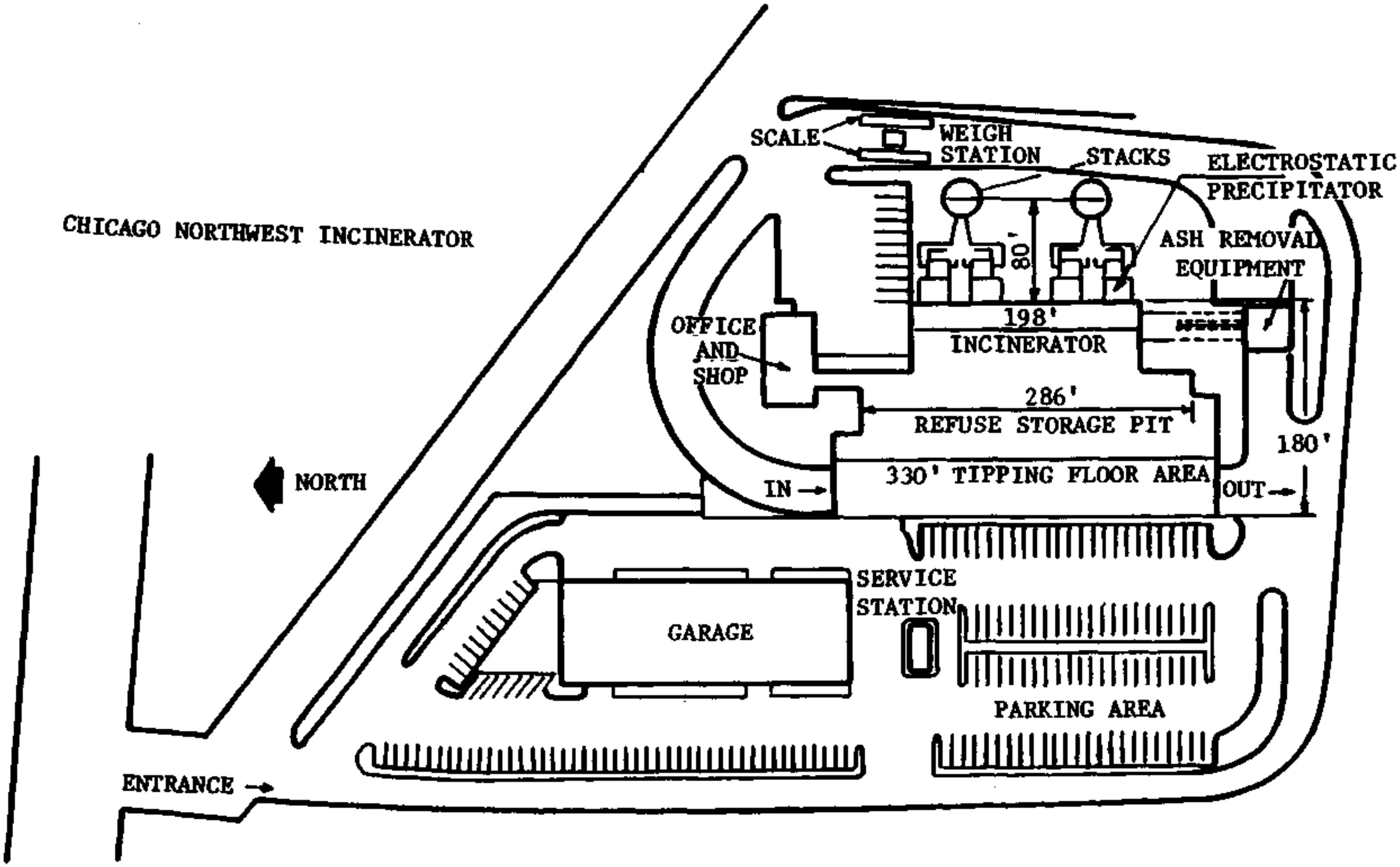


Figure 3-1. Layout of plant site

TABLE 3-1. CHARACTERISTICS OF CHICAGO NORTHWEST INCINERATOR

Number of incinerator units	4
Number of refuse cranes	3
Number of chimneys	2, each 250 feet high
Refuse pit capacity	9,700 cubic yards
Capacity of each crane bucket	5 cubic yards
Average heating value range of refuse	5,000 BTU/lb
Capacity: Refuse	1,600 tons/days
Steam Generation	440,000 lbs/hour
Furnace temperature	1,500° - 2,000°F
Stack gas temperature	450°F
Gas cleaning equipment	4 electrostatic precipitators
Precipitator efficiency	97%
Precipitator outlet grain loading	0.05 grains/std. cu. ft.

gases are reduced in temperature to approximately 450°F.

The residue from the grates and the fly ash collected by the ESPs are dumped into the ash discharger. The discharger which is partly filled with water quenches the ashes and via residue conveyors transferred to the ash building. The ashes are then screened. Salvageable metals are sold for reuse. The remaining ashes are taken from the ash building by trucks and used in construction projects or places as sanitary landfill.

A line diagram of the Incinerator is presented in Figure 3-2.

3.2 DETAILED DESCRIPTIONS

3.2.1 Refuse Handling

Mixed refuse from domestic sources is brought to the incinerator plant in collection trucks, each truck has a capacity of 5 tons or 25 cubic yards. The refuse averages 400 pounds per cubic yard. The refuse varies considerably in consistency and moisture content over a period of time and

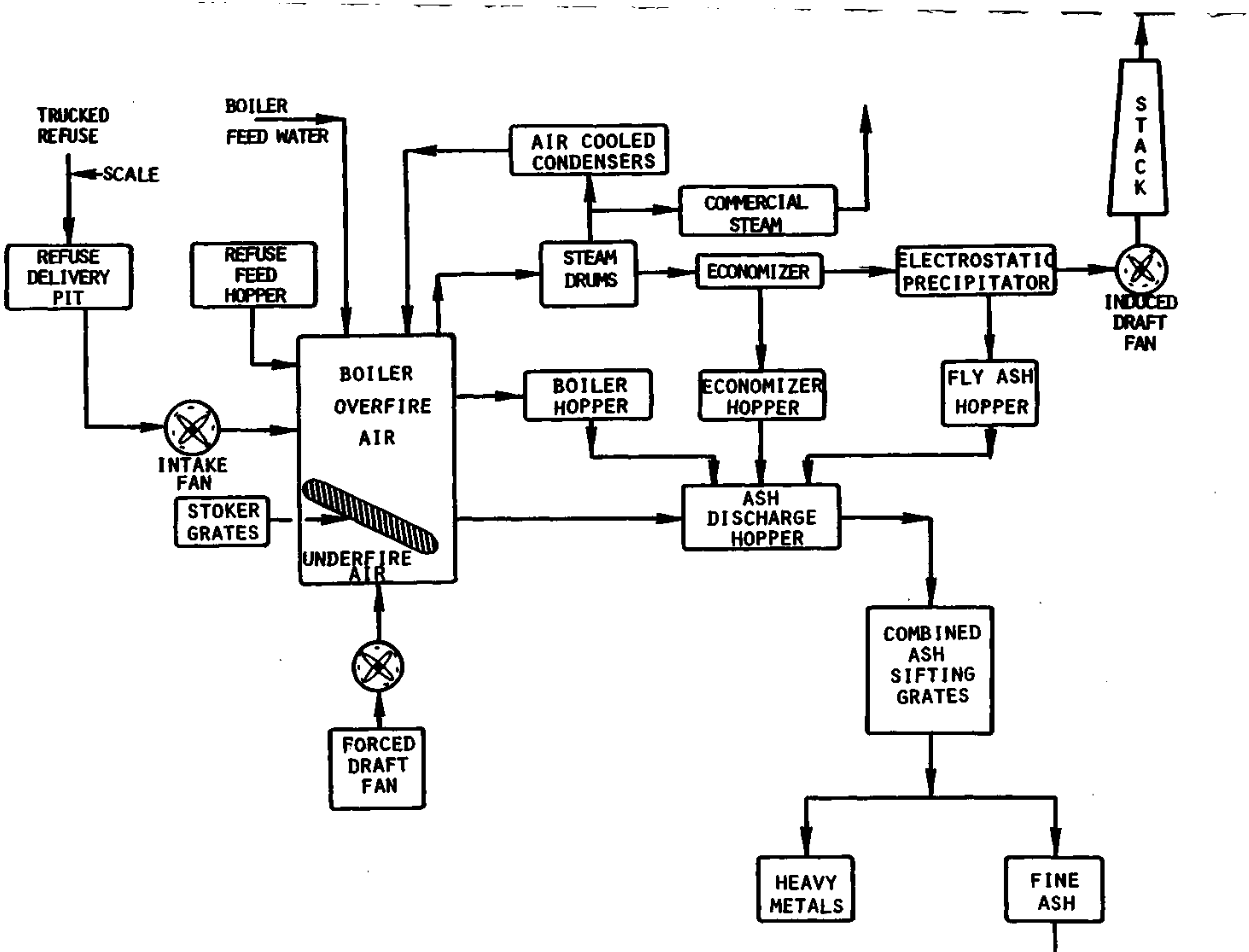


Figure 3-2. Flow diagram of Chicago Northwest Incinerator

this condition is reflected in the changeable calorific (heat) content of the refuse.

Trucks are weighed over scale platforms. After weighing these trucks are directed to eleven stalls in front of the refuse storage pit. After depositing their load the trucks leave the building through doors in the south end. Refuse items that are too large to be handled through the charging hopper and feed chute (such as mattresses, upholstered furniture, etc.) are removed. Bulky metal objects from the storage area are removed by trucks.

The refuse storage pit has a storage capacity of 9,700 cubic yards or 1,940 tons or sufficient "fuel" to last 29 hours when the four incinerators are operating normally. This necessitates refuse collection on six days of the week. However this is not always possible due to various reasons such as unfavorable weather etc. At such times auxiliary gas firing is utilized to meet steam demand and to keep the furnaces from cooling down.

The refuse is removed from the pit by one of three transfer cranes. These cranes are overhead, high speed, two-girder, single trolley, travelling, grab bucket cranes each of 8.5 tons capacity handling mixed refuse from the storage pit to the furnace charging hoppers. An auxiliary hoist of 2.5 tons capacity is provided on each of the end cranes and mounted on crane trolleys. Each crane bucket has a 5 cubic yard capacity and is a four-line, line-type grapple. All crane components are electric motor driven under control of an operator in a cab suspended from the bridge and located so as to permit the operator to see the bottom of the refuse storage pit as well as the charging hoppers. The cranes are capable of performing a maximum of 29 cycles per hour per crane including an allowance of approximately 20 percent for rehandling refuse and other interruptions. The cranes span 44' - 8" center to center of rails and the crane runaway is 286' - 0" in length.

Crane operations are manually controlled from within each respective crane cab. Each refuse transfer crane was initially equipped with solid-state computerized weighing systems to record the amount of material charged into the hoppers by each crane and also record into which hopper the material is charged. Due to various problems the use of the solid state systems was abandoned and now the number of times the refuse is charged into the hopper is monitored manually by the crane operator. Each charge is assumed to be of 5 cubic yards capacity.

3.2.2 Refuse Burning

The plant has four incinerators each having a nominal burning capacity of 400 tons per 24 hour day. Each incinerator has a charging hopper, feed chute, hydraulic powered feeders and stoker (manufactured by Josef Martin, Germany), boiler, economizer and fly ash hoppers. Draft throught the furnace (boiler) is provided by forced draft fans, overfire air fans and induced draft fans.

Refuse in the charging hopper of each incinerator flows by gravity from the hopper to three stoker feeders through a feed chute, the lower portion of which is water cooled. Near the bottom of each charging hopper is a hydraulic powered pivoted type gate normally open but closed when the feed chute is empty of refuse. The charging hopper gates are manually controlled through operation of a four-way valve on the charging floor. The stoker feeders at the bottom of the feed chute push the refuse into the stoker by the reciprocating action of their hydraulic powered rams. The stokers of each incinerator are assembled with three runs or sections and have a sloping activated surface consisting of 17 rows of grate steps. The grate sections incline from the hortizontal at an angle of 26°, the lower end being at the rear. The stoker is of the reverse acting, reciprocating grate type. Alternate lateral rows of grate steps have controlled continuous reciprocating action with the moving grate steps pushing in reverse direction to the flow of refuse. This action moves a portion of the burning refuse under the unignited material and thereby effects an agitation and blending of the whole burning mass. Combustion air entering from below the grates cools the grates, helps to agitate the burning refuse and supplies the oxygen which produces a maximum burn-out in the shortest length of grate travel.

Although the spacing between the grate bars comprises less than two percent of the total grate area, it is still possible for small siftings or ashes to find their way through the grate. These ashes are handled by the automatic sifting discharge which extends underneath the air plenum chambers serving the stoker. At regular intervals high pressure air is directed through the siftings channel, driving the siftings into the ash discharges.

In order to obtain maximum burn-out, the depth of the refuse bed is controlled by automatic discharge or clinker rollers located at the end of the grate. As the residue reaches this point it is dumped into the Martin ash discharger where it is immediately quenched in water. The residue, following quenching by means of a hydraulic powered ram is pushed up an inclined slope which permits draining. This produces a residue of less than 15 percent moisture, and permits dry type conveying. In addition to quenching, the ash discharger also serves as a water seal for the furnace. This seal prevents infiltration of air into the furnace which is under negative pressure.

Each refuse burning boiler is provided with two gas burners suitable for use with natural gas. They are automatically controlled and have an electric ignition.

3.2.3 Residue Handling

The residue leaving each incinerator ash discharger passes through a hydraulically operated bifurcated chute to one or the other of two residue conveyors. These apron type conveyors travel at a rate of 17 feet per minute and have a capacity of 35 tons per hour. Only one conveyor operates at a time and extends horizontally past the four incinerators. It discharges its load onto rotary screens and storage hoppers in the Ash Discharge building. The electric motor driven rotary screens separate material larger than 2 inches in diameter from smaller sized material. Hydraulic power operated diverting chutes are provided to direct the flow of residue away from the rotary screens and into a bypass hopper.

Material from the hoppers is removed from the plant by motor trucks. The weight of the residue leaving the plant is measured and recorded at the weighing station.

The residue conveyors also receive and transport stoker grate siftings and fly ash accumulations from the boiler hoppers, economizer hoppers, and the electrostatic precipitators. Stoker grate siftings collect in six hoppers under each of three stoker grate sections. The siftings are conveyed to the residue conveyors through automatically controlled, pneumatic cylinder actuated ash dampers to ducts connected to the residue discharge (drop) chute. Boiler fly ash is collected in four hoppers and the front two hoppers discharge to the stoker grates through ducts equipped with pneumatic cylinder actuated pendulum dampers. The rear two hoppers discharge to the residue discharge chute through a common connecting pipe equipped with slide gate and an electric motor driven rotary valve. Fly ash from the economizer hoppers passes through a common pipe connected to the discharge end of the conveyor handling fly ash from the electrostatic precipitator. The two fly ash hoppers located under each precipitator discharge ash onto a drag conveyor which transmits the fly ash into the incinerator building onto a conditioning conveyor. This conveyor discharges into the residue discharge chute. Water is mixed with the fly ash in the conditioning conveyor.

The fly ash handling system is designed for continuous operation and the various devices are actuated from controls on the stoker panel. The control of residue handling equipment is manual.

3.2.4 Steam Supply

Refuse with a calorific value of approximately 5,000 BTU per pound at the rate of 400 tons per day is used to generate 110,000 pounds per hour of steam at 250 psig. Each boiler has the capacity to produce up to 135,000 pounds/hour of steam. The stokers and boiler heating surfaces are designed to receive refuse of up to 6,500 BTU/lb. The allowable design of the stoker grate loading is 65 lbs/sq.ft. per hour and thus the average stoker heat release is 325,000 BTU per hour/sq.ft. of projected grate area.

The boilers are convection, water well, natural circulation types with economizers. Each boiler has 19,776 sq.ft. of heating surface and is designed for a 300 psig working pressure.

Steam produced in the boiler accumulates above the water surface in the steam drum and leaves the drum through double row of tubes connected to the saturated steam header outside of and supported on the boiler steam drum. From the saturated steam header the steam flows to the main header and then through branch lines to turbines driving fans and pumps, export lines and high pressure condensers. Steam at reduced pressure is also used for heating various systems such as water chiller absorption units, office buildings, low pressure condensers, etc.

When the steam produced in the plant is more than that required for operating the steam turbine equipment, heating purposes or export, the excess quantity "spills over" to the high pressure condensers located on the roof of the incinerator building. From the condensers the condensate flows to the deaerating feed water heater, the rate of flow being automatically controlled and modulated to equal the rate of condensation. The requirements for make-up to replace steam condensate lost or wasted are met by using softened water. The water softening unit includes duplex softening units containing synthetic type zeolite resin, a salt storage tank, a brine measuring tank, electric motor driven brine pumps and interconnecting piping. It has a nominal flow rate of 260 gpm and a maximum rate of 480 gpm.

From the feedwater heater, water flows by gravity to the inlets of the boiler feed pumps. There are four pumps, each having a nominal capacity of 400 gpm. The pumps are multi-stage, horizontal, centrifugal type. These pumps transmit the water to the boilers.

Each boiler has a continuous blowdown system with water drawn from the steam drums. The blowdown pipe lines from the four boilers extend to a single flash tank. Flash steam is returned to the deaerating feedwater heater at 5 psig. From the heat exchanger the blowdown water flows to an underground concrete blowdown tank where the water cools before overflowing to a sewer.

3.2.5 Combustion Air and Flue Gas

The incinerator stokers are designed to utilize 67,200 scfm of primary air (introduced under the stoker grates) at 18 inches w.c. and an overfire air (secondary) flow of 16,800 scfm at 15 inches w.c. Overfire air is introduced into the furnace to reduce stratification of gas and thus provide more complete combustion of the gases. The air enters through the front and rear water walls. The underfire air is discharged into several compartments under the stoker grate. The compartments are provided with dampers which are individually adjustable by manual operation of regulating stands located on the stoker operating floor. During the burning of refuse a constant air pressure is maintained under the stoker grates by means of automatic pneumatic controls.

Combustion air combines with the burning refuse to generate heat and raise the temperature of the flue gas to as high as 2000°F. At rated burning capacity and based on 50 percent excess air (dry) the flue gas flow rate at 550°F is estimated to be 142,300 acfm. The flue gas passes upward through the furnace, through the boiler passes and finally through the economizer to the electrostatic precipitator. As it passes through the boiler it transfers heat to the water. At the inlet to the electrostatic precipitator the temperature is reduced to approximately 500°F because of the above heat exchange. During the passage of the flue gas through the boiler passes and economizer the heavier fly ash particles drop out. Hoppers are provided below the boiler and economizer for the collection of the drop out material.

The plate type electrostatic precipitators (ESP) (one for each incinerator) have a series of vertical collector plates between which are suspended the charging electrodes. The ESP's are designed for an inlet grain loading of 1.6 gr/scf (70°F and 29.92 in Hg) and an outlet grain loading of 0.05 gr/scf with a collection efficiency of 97 percent. The gas velocity through the ESP is around 3 ft/sec.

From the precipitator the flue gas passes through a breaching continuation to the inlets of the induced draft fans and then through the 250 ft. stacks to the atmosphere.

A line diagram of the combustion air and flue gas system is provided in Figure 3-3.

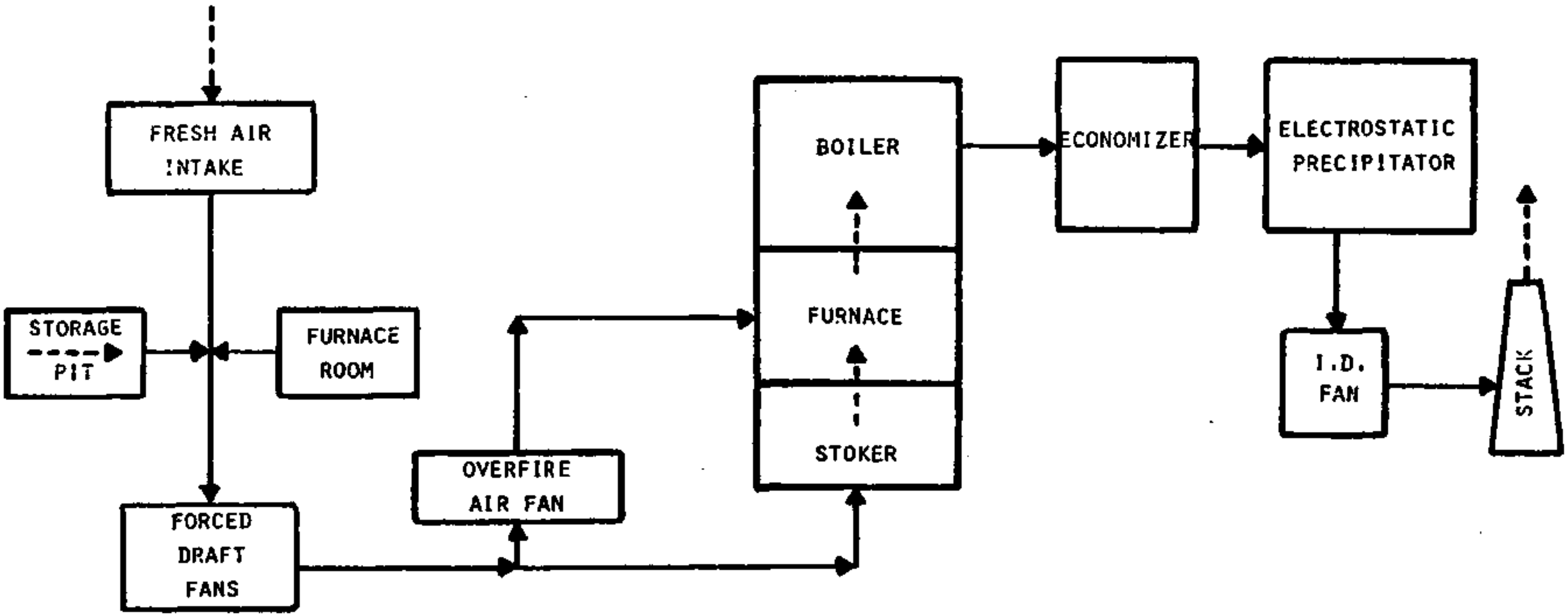


Figure 3-3. Combustion air and flue gas system

4.0 SAMPLING LOCATIONS

All sampling locations are identified in Table 4-1 and Figure 4-1. Figure 4-2 is a schematic depicting the traverse point locations at the stack. Figure 4-3 is a top view of the ESP inlet showing port locations, and Figure 4-4 is a cross sectional view of the ESP inlet depicting the traverse point locations.

The continuous monitoring probe was located on the South side of the ESP inlet duct utilizing one of the gas sampling ports and at a depth of approximately 4 feet. At the outlet, the monitoring probe was alternated between ports 2 and 3 and at a depth of 4 feet. These two ports were also used for the gas sampling trains.

TABLE 4-1. SAMPLING LOCATIONS

Solid Sample Locations

1 - Refuse derived fuel
2 - Fly ash
3 - Combined ash

Gaseous Sampling Locations

4 - Hi volume ambient air sampler
5 - ESP inlet
6 - ESP outlet

Liquid Sample Locations

7 - City tap water

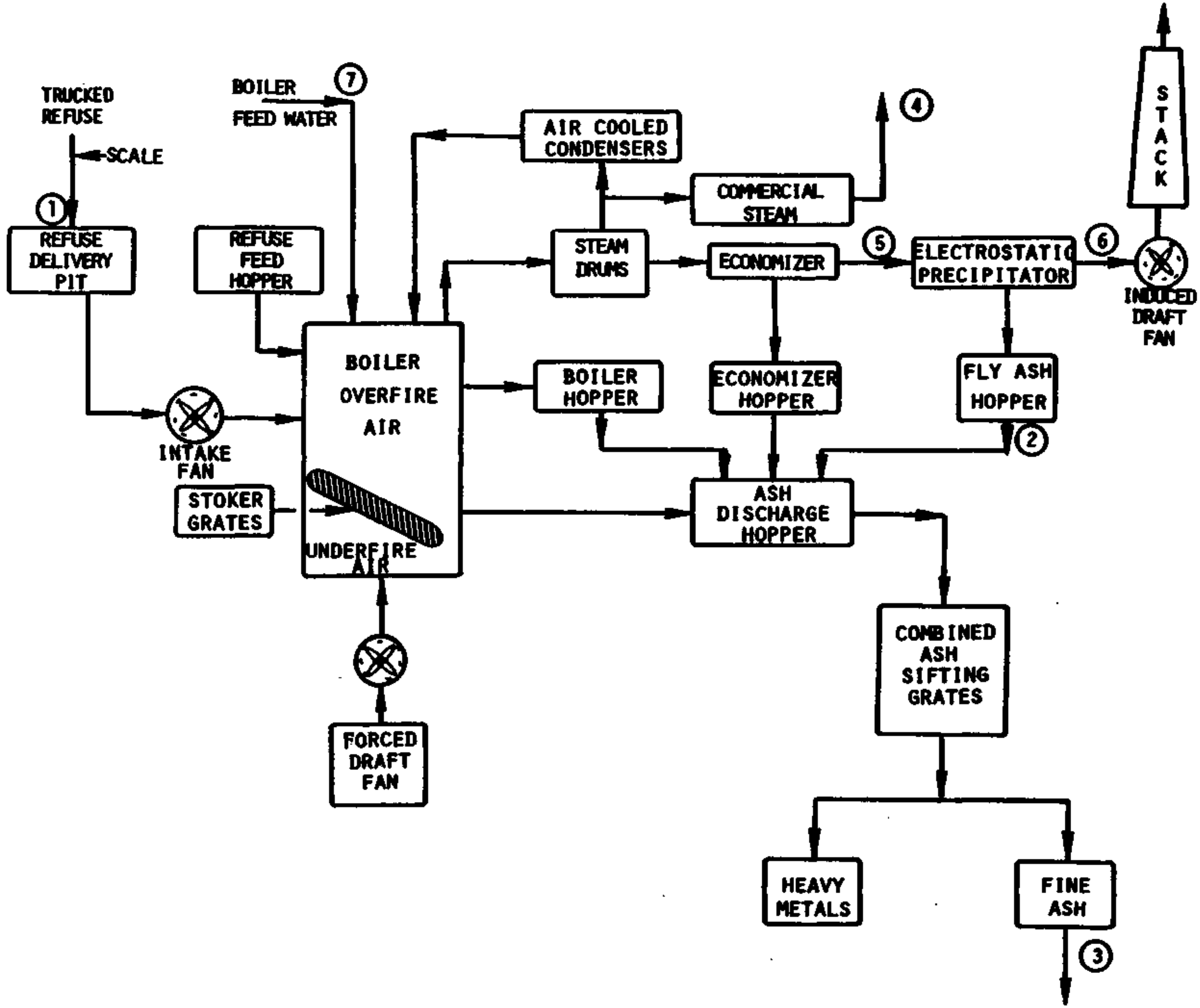
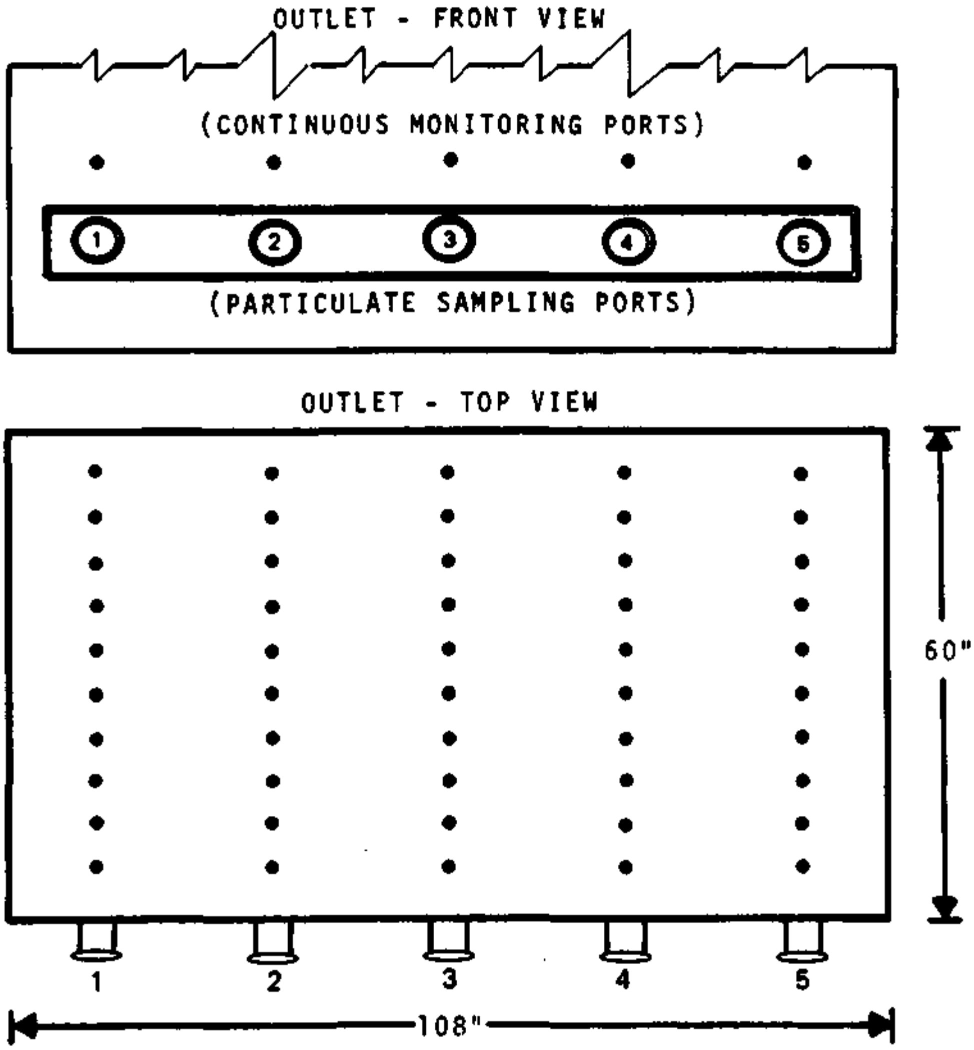


Figure 4-1. Flow diagram and measurement locations



SAMPLING POINTS - OUTLET

Traverse Point No.	Distance from Outside Edge of Nipple In.	Cm.
1	11.5	29.21
2	17.5	44.45
3	23.5	59.69
4	29.5	74.93
5	35.5	90.17
6	41.5	105.41
7	47.5	120.65
7	53.5	135.89
9	59.5	151.13
10	65.5	166.37

Figure 4-2. Outlet sampling position

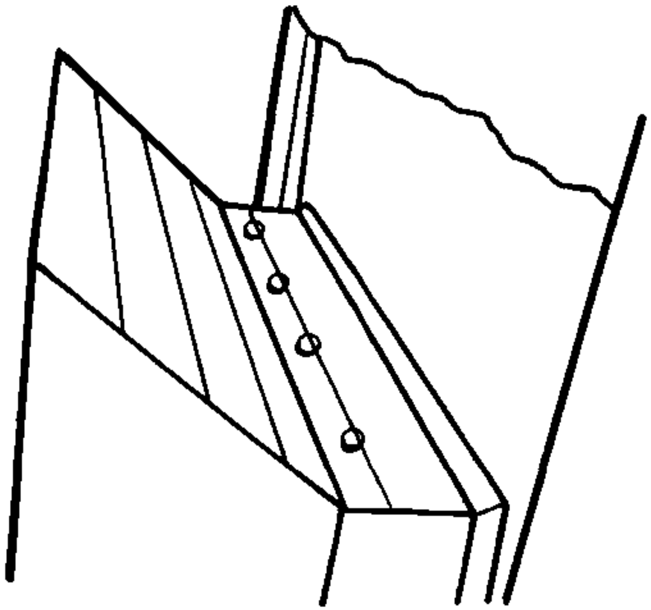
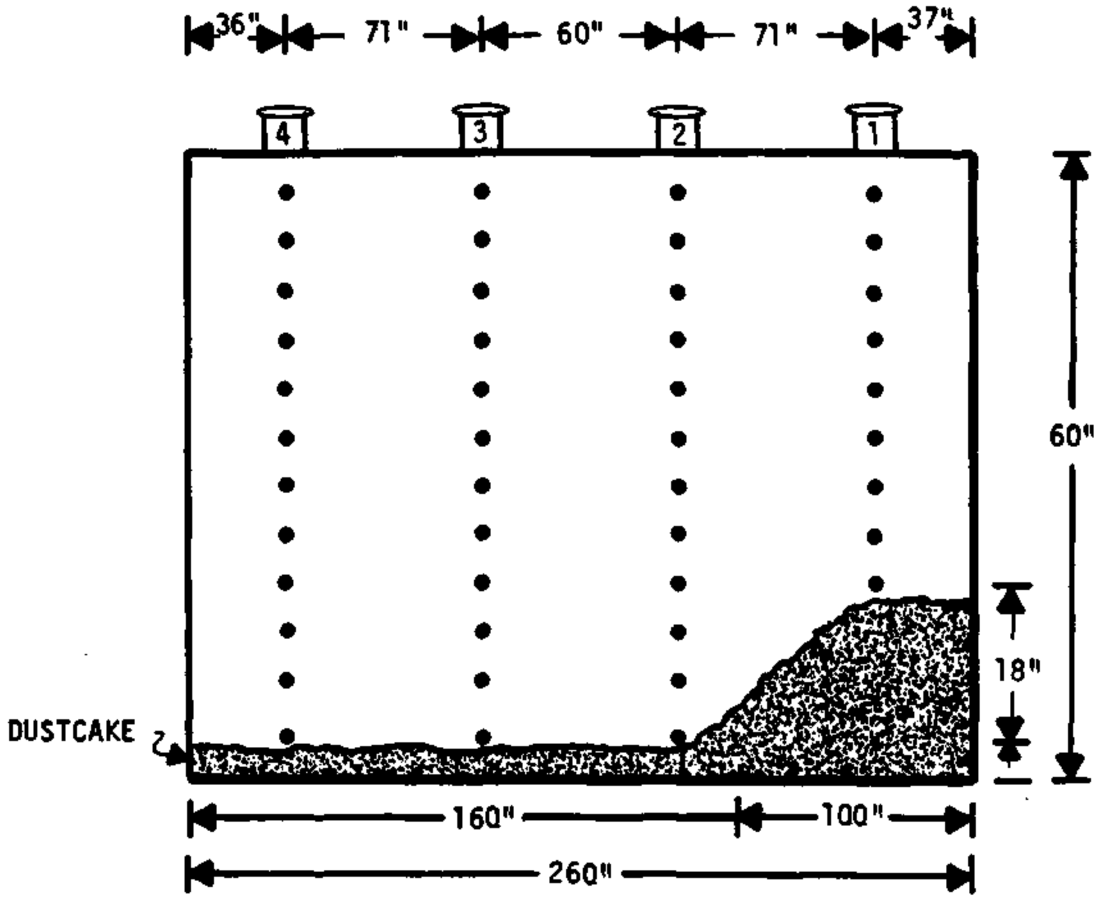


Figure 4-3. Top view of ESP inlet showing port locations



SAMPLING POINTS - INLET

Traverse Point No.	Distance from Outside Edge Nipple	
No.	In.	Cm.
1	11.5	29.21
2	15.375	39.05
3	19.625	49.35
4	23.875	60.64
5	28.125	71.44
6	32.375	82.23
7	36.625	93.03
8	40.875	103.32
9	45.125	114.62
10	49.375	125.41
11	53.625	136.21
12	57.375	145.73

Figure 4-4. Cross sectional of ESP inlet showing traverse point locations.

5.0 SAMPLING

This section provides information on the sampling program conducted at the Chicago Northwest Incinerator (CNI).

5.1 GAS SAMPLING

The original test plan called for sampling to be performed on Boiler No. 1. However, upon arriving at the test site, this unit had been taken off line for repairs. As all four (4) units at the Chicago Northwest facility are identical, the sampling effort was switched from unit 1 to unit 2. The flue gas sampling was performed at the electrostatic precipitator (ESP) inlet and at the duct leading from the precipitator to the stack. The stack was common to two boiler units and for this reason, no testing was performed at the stack level.

Sampling for organics was to be performed for fourteen consecutive days with three additional days for sampling of inorganic cadmium. Due to boiler down time and equipment malfunction, only eleven organic samples were taken. Sampling for organics was accomplished concurrently at the inlet and outlet utilizing two modified Method 5 trains (refer to Figure 5-1) at both sampling locations. Inorganic cadmium was only sampled at the stack and utilized one standard Method 5 train, Figure 5-2.

The sampling crew collected a ten m^3 (10 ± 1 m^3) sample by extracting the flue gas at a rate approximating the flue gas velocity. The particulate matter was collected in a cyclone and on the filter media. The gas stream was passed through an XAD-2 resin trap to absorb the organic constituents and through an impinger system to condense any moisture present in the gas. Parameters such as temperatures, pressures, and gas volumes were monitored throughout the sampling period. The sample fractions were recovered from the sampling trains and turned over to an MRI representative.

5.2 SOLID SAMPLING

During each test day, 3 solid streams: precipitator ash, combined ash, and refuse derived fuel (RDF) were sampled six times per day following a schedule set up by Research Triangle Institute (RTI). The sampling was coordinated between RTI, the sampling crew and plant personnel. The

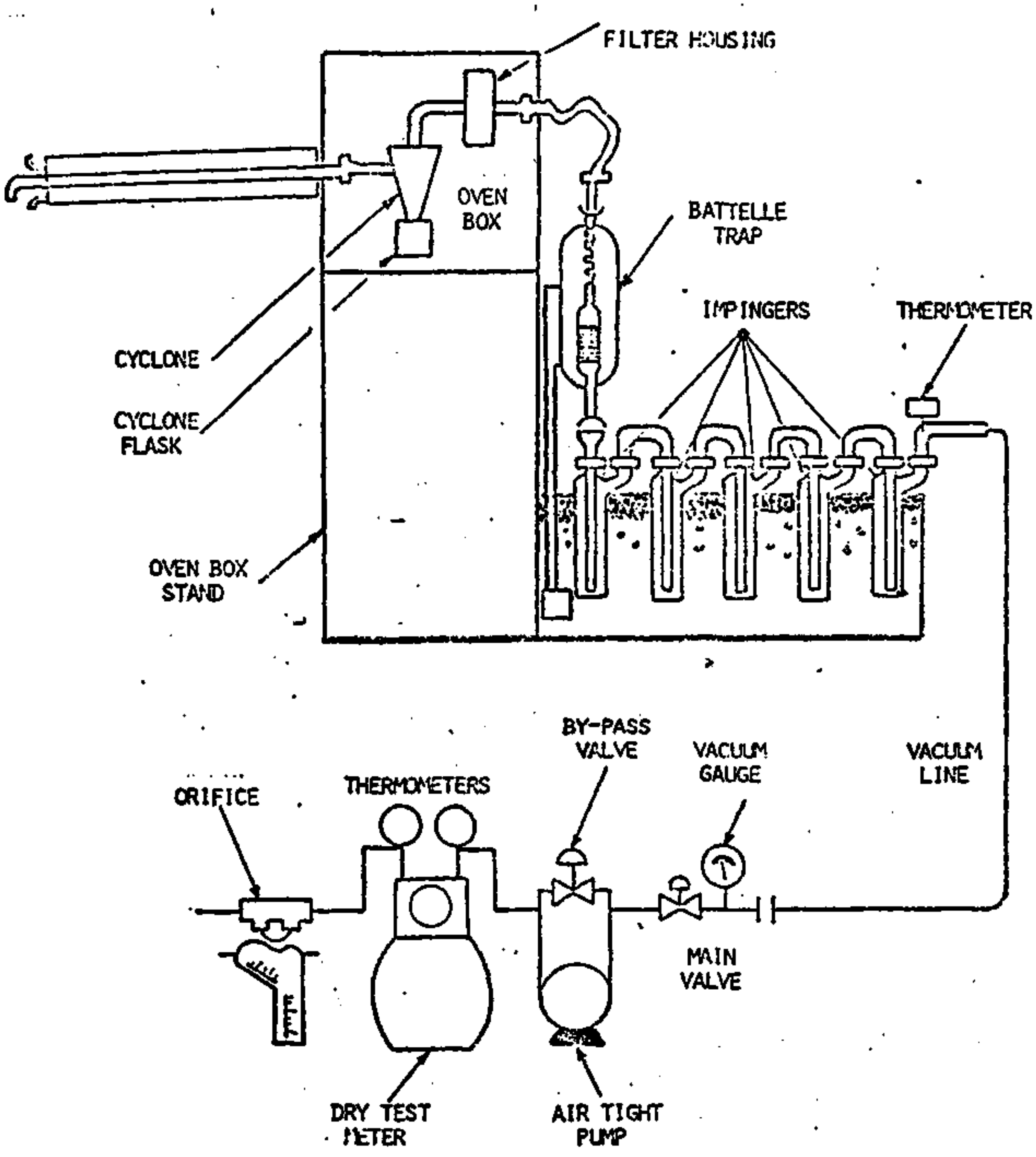


Figure 5-1. Sampling train

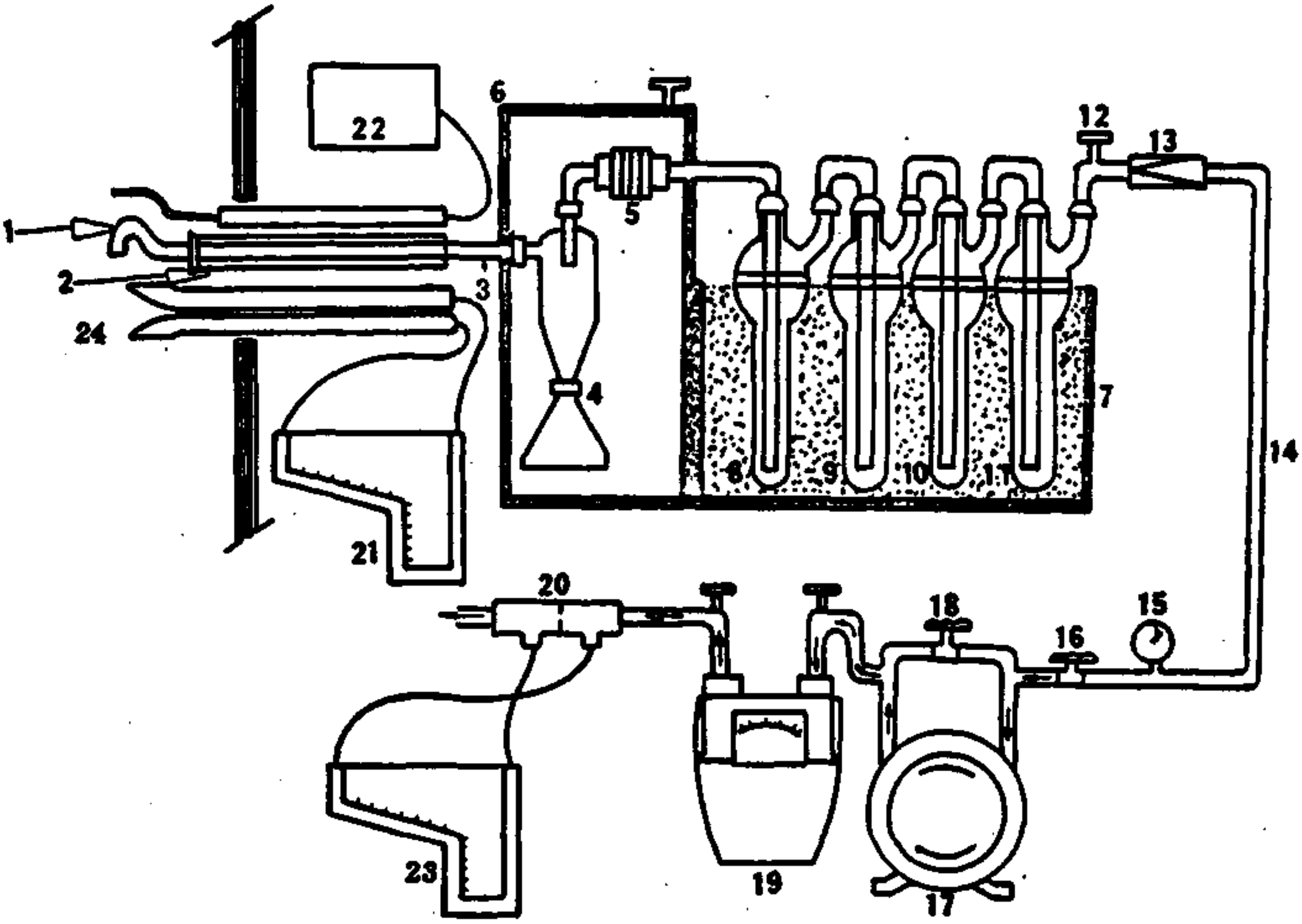


Figure 5-2. EPA Method 5 particulate sampling train

1) Calibrated nozzle
2) Glass lined probe
3) Flexible teflon sample line
4) Cyclone
5) Filter holder
6) Heated box
7) Ice bath
8) Impinger (water)
9) Impinger (water)
10) Impinger (empty)
11) Impinger (silica gel)
12) Thermometer
13) Check value
14) Vacuum line
15) Vacuum gauge
16) Main value
17) Air tight pump
18) Bypass value
19) Dry test meter
20) Orifice
21) Pitot manometer
22) Potentiometer
23) Orifice manometer
24) S type pitot tube

schedule provided the basis for collection of unbiased samples by obtaining a random selection from the multiple sources available for sampling. This approach was taken to avoid any cyclic biases which might have been present in the daily operation of the power plant.

The CNI sampling plan did not call out specific sampling protocol for the RDF. At a meeting prior to the start of testing, it was decided that the RDF would be sampled 6 times during the course of the day. The sample was taken directly from the charge hopper, utilizing a post-hole digger and alternating grab spots across the hopper. At the conclusion of RDF sampling, one days collection (6 samples) was shredded, mixed and stored in an amber glass jar. MRI had purchased a large leaf mulcher to do the shredding. TRW performed the shredding of the sample provided by GSRI

5.3 LIQUID SAMPLING

Only one liquid stream (city water) was sampled at the incinerator facility. The sampling was performed by GSRI. The sampling protocol and frequency of sampling will be supplied by GSRI in their report.

5.4 HI VOLUME SAMPLER

To monitor the ambient air background, a high volume ambient air sampler (Figure 5-3) was used. It was placed on the roof of the Chicago Northwest Incinerator facility to obtain a representative background utilizing outside ambient air rather than sampling air inside the building that could have been contaminated or influenced by the combustion process.

5.5 QUALITY ASSURANCE

A quality assurance sample was also taken of the final test day. To collect the quality assurance sample, two sampling trains were placed at the same point in the same port at the inlet of the ESP. No traversing was performed. Both trains were run at the same isokinetic rate for the same duration as a normal test day. Also during the Q/A day, solids and liquids were collected as in a normal test day.

5.6 SAMPLING TRAIN BACKGROUND

To obtain the train background (blank) an entire sampling train, including resin trap filter and impinger solutions was set up at the ESP inlet. The train was taken to normal operating temperatures and allowed to

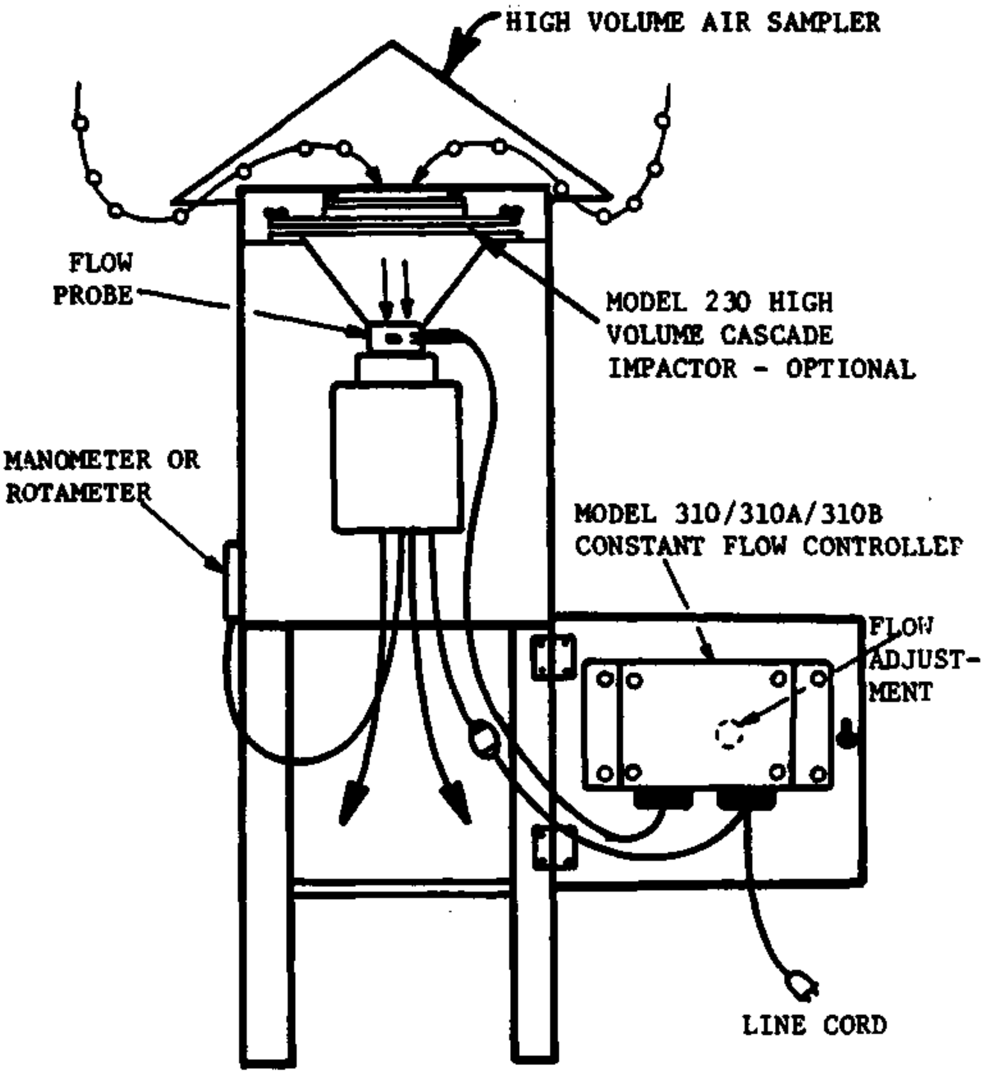


Figure 5-3. Ambient air sampler.

remain at these temperatures for one (1) hour. All train components were recovered as a normal run and all sample blanks were given to an MRI representative.

5.7 SAMPLE RECOVERY

Upon completion of testing, the sampling equipment was brought to the cleaned laboratory area for recovery. Each sampling train was kept in a separate area to prevent sample mixup and cross contamination. The individual sample train components were recovered per the following:

- Dry particulate in cyclone + cyclone flasks were transferred to cyclone catch bottle.
- Probe was wiped to remove all external particulate matter near probe ends.
- Filters were removed from their housings and placed in proper container.
- After recovering dry particulate from the nozzle, probe, cyclone, and flask, these parts were rinsed with distilled water to remove remaining particulate. They were subsequently rinsed with B & J acetone and cyclohexane and put into a separate container. All rinses were retained in an amber glass container.
- Sorbent traps were removed from the train, capped with glass plugs, and given to an on-site Midwest Research Institute (MRI) representative.
- Condensing coil, if separate from the sorbent trap, and the connecting glassware to the first impinger was rinsed into the condensate catch (first impinger).
- First and second impingers were measured, volume recorded and retained in an amber glass storage bottle. The impingers were then rinsed with small amounts of distilled water, acetone and cyclohexane. These rinsings were combined with the condensate catch. Rinse volumes were also recorded.
- Third and fourth impingers were measured, volume recorded and solutions discarded.
- Silica gel was weighed, weight gain recorded and regenerated for further use.

To maintain sample integrity, all glass containers were amber glass, with Teflon-lined lids.

5.8 OBSERVATIONS DURING RECOVERY

- The first day setup of impingers did not include H_2O_2, as the shipment had not been delivered from the manufacturer.
- Many filters that were supplied for the particulate catch, had the identification number stamped in blue ink on the top; or, particle gathering side.
- Some Battelle Traps were packed with too much glass wool. (As a result, flow rate was somewhat restricted.) The probe and oven box did not remain hot enough to keep the cyclone and flask dry. For the first few days of testing, the cyclone had moisture on the inside walls, so no dry particulate could be collected.
- On 5/10/80, the wind blew the Hi Volume Air sampler cabinet over. The cabinet had to be moved to a less exposed area nearer the building.
- On 5/5/80, 5/8/80, and 5/9/80 yellow residue was noted in the teflon line connecting the back of the filter housing to the front of the Battelle cooling coil. When the teflon line was rinsed with acetone, the rinse turned to reddish-brown.
- When the filters were not kept completely dry throughout the particulate test period, the filter paper would stick to the rubber gasket and was very difficult to completely remove.
- A reddish color remained on the inlet filter backing plates on 5/8/80 and 5/15/80. The color washed off with water, and the rinse was discarded.
- The inlet glass transition tubes connecting the probe to the cyclone, had to be wrapped in an attempt to keep moisture and particulate from dropping out and depositing on the walls.
- All parts were inspected for cleanliness after the water and acetone rinses, but before the cyclohexane rinse. Cyclohexane does not rapidly evaporate and gives any part rinsed with it the appearance of being clean. In reality the parts were still wet and masked any particulate that remained on the walls.

6.0 CALIBRATION

This section describes the calibration procedures used prior to conducting the field test at Chicago Northwest Incinerator facility. Figure 6-1 shows the calibration equipment and how it was set up.

6.1 METHOD FIVE CALIBRATION DATA

6.1.1 Orifice Meter Calibration

The orifice meter calibration is performed using a pump and metering system as illustrated in Figure 6-1(a). The dry gas meter with attached critical orifice is run at various orifice flows for a known time. After each run the volume of the dry gas meter, meter inlet/outlet temperatures, time, and orifice setting is recorded. The orifice meter calibration factor is derived by solving the equation.

$$\Delta H@ = \frac{0.317\ \Delta H}{Pb\ (T_d + 460)} \left[\frac{(Tw + 460)\ \theta}{Vw}\right]^2$$

where

ΔH = Average pressure drop across the orifice meter, inches H_2O

Pb = Barometric pressure, inches Mercury

T_d = Temperature of the dry gas meter, °F

Tw = Temperature of the wet test meter, °F

θ = Times, minutes

Vw = Volume of wet test meter, cubic feet

The $\Delta H@$ yielded is utilized to adjust the sampling train flow rate by regulating the orifice flow.

6.1.2 Dry Gas Meter Calibration

Meter box calibration consists of checking the dry gas meter for accuracy. The dry gas meter with attached critical orifice is connected to a wet test meter (see Figure 6-1(b) below) and run at various orifice flows for a known time. After each run wet and dry gas meter volumes, temperatures, time, and orifice readings are recorded. Utilizing the equation:

$$V = \frac{Vw\ Pb\ (Td + 460)}{Vd\ (Pb + \frac{\Delta H}{13.6})\ (T_w + 460)}$$

where

V = Volume correction factor

Vw = Volume of wet test meter, cubic feet

Pb = Barometric pressure, inches mercury

Td = Temperature dry gas meter, °F

Vd = Volume of dry gas meter, cubic feet

ΔH = Average pressure drop across the orifice meter, inches H_2O

T_w = Temperature of wet test meter, °F

a volume factor which compares the dry gas meter with the wet test meter is obtained.

6.1.3 Pitot Tube Calibration

Pitot tubes are calibrated on a routine basis utilizing two methods.

The type S pitot tube specifications are illustrated and outlined in the Federal Register, Standards of Performance for New Stationary Sources, [40 CFR Part 60], Reference Method 2 (refer to Figure 6-1(c)). When measurement of pitot openings and alignment verify proper configuration, a coefficient value of 0.84 is assigned to the pitot tube.

If the measurements do not meet the requirements as outlined in the Federal Register, a calibration is then performed by comparing the S type pitot tube with a standard pitot tube (known coefficient of 1.0). Under identical conditions, values of ΔP, for both S type and standard pitot tube are recorded using various velocity flows (14 fps to 60 fps). The pitot tube calibration coefficient is determined utilizing the following equation,

$$\text{Pitot Tube Calibration Factor (CP)} = (\text{Standard Pitot Tube Coefficient}) \times \left[\frac{\Delta P \text{ reading of std. pitot}}{\Delta P \text{ reading of S type pitot}}\right]^{1/2}$$

The coefficient assigned to the pitot tube is the average of calculated values over the various velocity ranges.

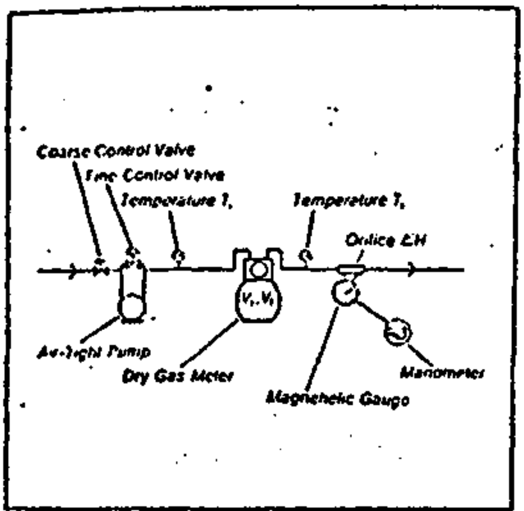


Figure 6-1(a)
Orifice meter calibration

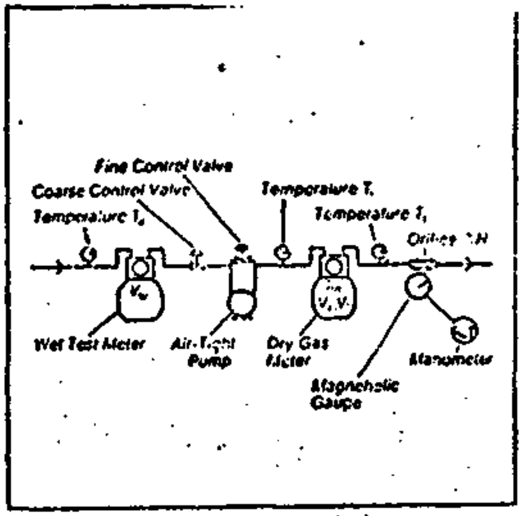


Figure 6-1(b)
Dry gas meter calibration

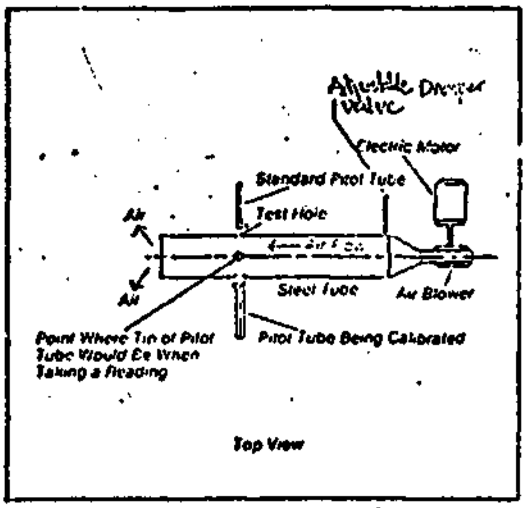


Figure 6-1(c)
Equipment used to calibrate pitot tubes

Figure 6-1. Calibration equipment set-up procedures

6.1.4 Nozzle Diameters

The nozzle diameters were calibrated with the use of a vernier caliper. If the nozzle showed excessive wear or was considered not fit for use, it was discarded.

6.2 INSTRUMENT CALIBRATION

The manufacturer's recommended calibration procedures were used with the following gases:

Zero gas: Nitrogen, high purity dry grade (99.997%)
Union Carbide Co., Linde Division

Calibration gas:

Carbon monoxide	798.5 ± 0.8 ppm
Carbon dioxide	11.93 ± 0.01%
Propane	39.6 ± 0.04 ppm
Oxygen	5.03 ± 0.005%
Nitrogen	Balance

(all gases contained in one cylinder)

Scott Environmental Technology Inc.
Specialty Gas Division

Zero and Calibration adjustment were made prior to the start of the test day. Zero drift checks were made at the end of each test period. Data was recorded every fifteen minutes thus providing two data points per hour for each sampling position, or four data points per hour for a single sampling position

7.0 TECHNICAL PROBLEMS AND RECOMMENDATIONS

This section describes some of the problems encountered during the Chicago Northwest Incinerator test program and recommends a solution to these problems.

7.1 PROBLEMS

- Electrical outlets were not installed on schedule (lost time - 1 day).
- One of the tubes in Boiler No. 2 developed a leak. The boiler had to be shutdown for repairs. This caused a delay of one day.
- The boiler grates malfunctioned and required cleaning. This resulted in down time of one day.
- Sampling equipment malfunctions caused further delays. This was due to:
    1) Difficulty in containing leaks during equipment operation.
    2) Failure of oven box heaters.
    3) Drift problems of the Beckman 865 CO analyzer. The analyzer had to be taken off line and subsequent inspection by manufacturer indicated that the stationary shutters were knocked out of alignment. This resulted in the loss of 4 days of CO data before a replacement was obtained.

7.2 RECOMMENDATIONS

Most of the above problems frequently occur in the field and should be considered normal during the course of a major field effort. The instrument problem may have been caused during shipment. Perhaps, stronger shipping containers should be used in the future.

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16. Abstract (Limit: 200 words) This pilot study was conducted as a prelude to a nation wide survey of organic emissions from major stationary combustion sources. The primary objectives of the pilot study were to obtain data on the variability of organic emissions from two such sources and to evaluate the sampling and analysis methods. These data are used to construct the survey design for the nationwide survey. The compounds of interest are polynuclear aromatic hydrocarbons (PAHs) and chlorinated aromatic compounds, including polychlorinated biphenyls (PCBs), polychlorinated dibenzo-p-dioxins (PCDDs), and polychlorinated di-benzofurans (PCDFs). Of particular interest is 2,3,7,8-tetrachlorodibenzo-p-dioxin (TCDD). In addition total cadmium was also determined in special samples from both plants to meet special Environmental Protection Agency (EPA) needs.

A summary of the results of this study is contained in Section 2 of this report. Section 3 presents recommendations for future work. Brief descriptions of the two combustion sources are contained in Section 4. The sampling and analysis methods are described in Sections 5 and 6. Sections 7 and 8 present the field test data and analytical results. The analytical quality assurance results are summarized in Section 9. Section 10 presents the emissions results and Section 11 is a statistical summary of the emissions results.

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