DOE/ET/40291-1

MASTER

Environmental
Data
Corporation

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

**DEMONSTRATION OF THE
ENVIRONMENTAL DATA CORPORATION
SPECTRAL FUEL CONSERVATION SYSTEM
PROGRAM PLAN**

**Submitted to
Division of Industrial Energy Conservation
U.S. Department of Energy
Washington, DC**

**Submitted by
Environmental Data Corporation
Monrovia, CA**

November 15, 1979

DISCLAIMER

This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

TABLE OF CONTENTS

<u>Chapter</u>		<u>Page</u>
1	INTRODUCTION AND BACKGROUND	1
2	STATEMENT OF THE PROBLEM.....	5
3	TECHNICAL APPROACH.....	7
	3.1 TASK 1 - PROGRAM MANAGEMENT.....	7
	3.2 TASK 2 - DEMONSTRATION SITE CRITERIA.....	7
	3.3 TASK 3 - DEMONSTRATION SITE SELECTION.....	11
	3.4 TASK 4 - BASELINE OPERATING DATA.....	13
	3.5 TASK 5 - CONTROL ENGINEERING.....	14
	3.6 TASK 6 - EQUIPMENT SELECTION AND PROCURE- MENT.....	14
	3.7 TASK 7 - INSTALLATION AND STARTUP.....	15
	3.8 TASK 8 - OPEN-LOOP PERFORMANCE TESTING....	17
	3.9 TASK 9 - CLOSED-LOOP PERFORMANCE TESTING.	18
	3.10 TASK 10 - TECHNICAL ANALYSIS.....	18
	3.11 TASK 11 - ENERGY SAVINGS ANALYSIS.....	19
4	PROGRAM MANAGEMENT AND SCHEDULE.....	21
	APPENDIX A - TECHNOLOGY DESCRIPTION.....	25
	APPENDIX B - ASME TEST FORM FOR ABBREVIATED EFFICIENCY TEST.....	37

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

ABSTRACT

This document is submitted in compliance with the reporting requirements of Contract No. DE-AC02-79CS40291. The purpose of this program is to demonstrate and quantify the amount of fuel that can be saved if the Spectral Fuel Conservation System (SFCS) developed by the Environmental Data Corporation (EDC) is installed in coal-fired industrial boilers.

Of central importance to the program are the selection of an appropriate test site and the preparation and methodical application of a comprehensive test strategy. Consequently, the sections dealing with these topics in the proposal have been considerably expanded in this program plan to include as much preparatory thinking as is possible at this early stage. The remainder of this document is essentially an updated version of the technical portion of the proposal. No change in the schedule is anticipated.

1. INTRODUCTION AND BACKGROUND

Today the United States has an urgent need for techniques and equipment for minimizing fuel consumption while at the same time satisfying important energy requirements. One of the best places to begin addressing this need is in fossil-fueled boilers. A large industrial power boiler is a complex system consisting of a multiplicity of burners arranged in rows or banks. Fuel (oil, gas, coal, or combinations thereof) is fed to the boiler in response to the load demands on the system. Simultaneously, a combustion control system feeds air to the boiler in an amount appropriate to the quantity of fuel. The objective is to provide an optimum ratio of air to fuel in order to maximize power output per unit of fuel input, while at the same time maintaining emitted air pollutants within required limits.

In a boiler, individual burners will, at any given moment, have differing operating characteristics. This is due to the fact that the burners tend to wear at slightly differing rates; they become dirty or partially clogged so that the fuel flow or airflow may be restricted; and the geometry of the boiler itself creates different air/fuel conditions in different regions of the combustion chamber. Accordingly, a functioning boiler normally contains multiple burners, each operating slightly differently. Frequent cleaning and periodic replacement of the burners can assist in maintaining the boiler at optimum working order, but the inherent characteristics of a boiler make it very difficult to completely balance all variations in a conventionally operated facility. Balance, even when achieved, will be only for a particular fuel type, load, desired air/fuel ratio, etc., and must be reset whenever one of the conditions changes.

For any given fuel input to the boiler, there is a theoretical amount of air that will mathematically yield complete combustion of the fuel. Because of the variables discussed above, it is never possible to attain this ideal in practice.

If the air supply is insufficient, incomplete combustion will result. The consequence of incomplete combustion is that unburned or partially burned fuel goes up the stack, as smoke and other pollutants, and carries with it wasted energy content that has not been used. Accordingly, standard operating practice requires a level of "excess" air to be provided at all times to ensure essentially complete combustion.

On the other hand, too much excess air has its own deleterious consequences. As excess air is added, the production of NO_x increases, creating an air pollution problem. Also, increased oxidation of SO_2 to SO_3 occurs, leading to increased back-end corrosion in the boiler. Furthermore, in the all important energy area, because the "extra" excess air is heated before it flows up the stack, it represents a significant direct energy loss. One should also not overlook the increased power consumption by the forced and induced draft fans that feed combustion air to the boiler.

From the foregoing it is apparent that excess air must be maintained within a controlled range. The closer the boiler can be made to operate to its theoretical air/fuel ratio (zero excess air), while still achieving complete combustion, the more efficient will be the use of fuel.

A potentially powerful technique for improving boiler efficiency is to fire the fuel with a level of excess air as low as possible yet consistent with achieving complete combustion and stable operation. Firing with low excess air enables stack thermal losses to be kept to a minimum. In some cases, fuel consumption can be reduced by up to 7 percent. Actual fuel savings will, of course, depend on the efficiency of the boiler and its utilization. For example, an industrial boiler that operates at 5-percent excess oxygen will have a stack loss of 12.5 percent at a stack temperature of 375°F. This same boiler operating at 1-percent excess oxygen will have a stack loss of only 10.5 percent at 350°F. This represents an increase in thermal efficiency of 2 percent and a fuel saving of 2.2 percent.

In practice, the general procedure is to fire steam boilers with excess air levels significantly above stoichiometric, because practical limitations caused by maldistributions in fuel and air frequently require oxygen levels significantly above the stoichiometric value. High excess air levels result in a significant boiler efficiency penalty because of the higher stack thermal losses resulting from the extra airflow. In front- and/or rear-fired boilers, maldistributions of fuel and air are likely to be greatest when the fuel is pulverized coal.

Because of the significance of coal and coal conversions in the national energy policy, the need for advances in coal-burning technology to maximize efficiency and minimize pollution are immediately recognizable.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

2. STATEMENT OF THE PROBLEM

The purpose of this program is to demonstrate and quantify fuel savings resulting from the installation of EDC's Spectral Fuel Conservation System (SFCS) on a coal-fired industrial boiler. The effort is aimed at demonstrating, on an industrial boiler, high efficiency, low excess air, and coal combustion, with minimum pollution utilizing EDC's SFCS. The scope of work includes the installation, operation, and analysis of an SFCS on a front-fired, multiburner, industrial boiler utilizing pulverized coal as its sole or primary fuel.

This program addresses an inherent difficulty associated with firing coal under optimum efficiency and minimum pollution conditions; that is, the heretofore inevitable imbalance of fuel and air at individual burners.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

3. TECHNICAL APPROACH

The primary program activity is the testing of the Spectral Fuel Conservation System (SFCS) in an industrial coal-fired boiler to demonstrate its effectiveness in reducing fuel consumption. This is achieved by creating and maintaining low-excess-air firing conditions at each burner, and/or by equalizing the air supply to all burners. Proper testing in an appropriate facility is therefore essential to the success of the program.

The technical approach outlined in this section builds upon two main factors: the selection of an appropriate test facility, and the development and implementation of a suitable testing strategy and procedure. A third and equally important element is the host company's degree of enthusiasm and cooperation in the program. In large measure, this will depend on the test protocol, the comprehensiveness and usefulness of the test, its orderly implementation within a reasonable amount of time, and the precautions taken to prevent any disruption in plant operations.

The following is a detailed description of the tasks required to accomplish the objectives of the program.

3.1 TASK 1 - PROGRAM MANAGEMENT

The purpose of this task is to coordinate and direct the activities of all program participants, including a liaison with DOE, and reporting and documentation. The Program Manager will coordinate the efforts between EDC, Thermo Electron, and the host industrial concern. He will also be responsible for program staffing, scheduling, and financial controls, and will be called upon to make managerial decisions of both technical and economic natures. Program documentation will consist of monthly progress reports and a comprehensive final report.

3.2 TASK 2 - DEMONSTRATION SITE CRITERIA

The purpose of this task is to develop criteria to aid in the selection of the best possible demonstration site.

As previously noted, the selection of an appropriate test site is important to the success of this program. Thus, certain criteria need to be developed in order to choose the best possible demonstration site. We have broken down these criteria into two categories: (1) those that are considered necessary to the successful demonstration of the system, and (2) those that, although not absolutely necessary, would be extremely desirable in terms of time, effort, and cost to the program.

The first and most obvious necessary requirement is that the demonstration installation be a facility which uses pulverized coal as its primary fuel, and is able to operate on this fuel only for the entire duration of the test period. It is also desirable that the coal used during the demonstration period not vary considerably in grade, moisture content, etc. This would give a greater consistency of actual flame composition over the demonstration period and thus lend added credibility to the data on response versus fuel/air ratio. This desired criterion is not meant to imply that the Spectral Fuel System would not respond equally well to coals of different grades, rather, it merely ensures that all comparison data are generated under the same conditions of flame composition.

Another desirable criterion is that the test boiler be of medium output, approximately in the 200,000 to 500,000 lb/hr range of peak steam output. There are several reasons for this. First, boilers in this capacity range generally are equipped with at least four, and not more than six, burners. This is ideal for testing the ability of the SFCS to regulate combustion at each burner while at the same time limiting equipment and installation expenditures. Second, load variations are more easily achieved on smaller boilers, as are changes in fuel and air rates. The ability to vary the load over a wide range and to independently vary the rate of secondary air input is crucial to a successful demonstration of the system. Consequently, the site considered must either possess this ability or be equipped with a control system that could be used to provide it prior to the installation and testing of the SFCS.

Secondary air control is stressed here for two reasons. First, in a pulverized coal-fired boiler it is very difficult to accurately vary the rate of fuel feed over the time intervals required for testing. Second, it is quite effective to vary secondary air feed while burning coal at a constant rate, and to control this air input rate in the final demonstration phase. In brief, it is much more practical to vary secondary air than it is to vary fuel input rate.

Most coal-fired boilers are equipped with systems which control, to some extent, the amount of oxygen in the flue gas. Controlling this excess O_2 is crucial to efficient combustion of the fuel, as the O_2 control loop controls the damper drives and coal feeders, and sets limits on system tolerance. Oxygen control is mandatory for the proper operation of the SFCS. Further, since the purpose of the SFCS is to "fine tune" the operation of the boiler through the monitoring of individual burners, precision control of overall excess O_2 is essential. For this reason, the test site boiler must possess a well-maintained control system capable of controlling flue gas O_2 concentrations to within ± 0.5 percent. This may require some modification or updating of the existing control system at the proposed test facility.

The SFCS functions with the aid of an Environmental Data instack DIGA gas monitor. In order to "close the loop" on the system, it is necessary to have accurate instrumentation for the real-time monitoring of flue gas concentrations. This is especially important in the case of carbon monoxide concentration in the flue gas, as CO is one of the most consistently used and reliable indicators of burner efficiency (see for example: "CO as a Combustion Control Parameter," by Anson, Clarke, Cunningham, and Todd, in Combustion, March 1972, or "Precise Combustion Control Saves Power," by L. Gilbert, in Chemical Engineering, June 1976). However, CO_2 and NO are also valuable indicators of the flame chemistry at the burners.

NO concentration generally decreases as stoichiometric conditions are approached. Conversely, CO_2 concentration rises to the stoichiometric level. A bad flame, however, can contain "hot spots", which can significantly lower boiler efficiency. In these "hot spots", N_2 , from the primary or secondary air, is being oxidized at a greater than normal rate. Although in this case it is possible for all other parameters to be normal, the high NO content would indicate that a problem exists. The Spectral Flame Analyzer (SFA) system would be able to identify at which burner or burners the problem was occurring and corrective measures could then be taken.

Additional gas monitoring is essential if boiler effluents are to be properly measured and general improvement of flue gas quality is to be determined. The gases to be monitored here would be NO, SO_2 , CO_2 , and CO. An opacity measurement capability would also be desirable, as opacity, along with CO, provides an excellent "early warning" in the event of possible flameout or extremely poor boiler operation.

In light of the above, it will be necessary to measure CO concentrations, at the very least, with an in-stack DIGA system. Preferably, a 5-channel (CO , CO_2 , NO, SO_2 , opacity) instrument should be available at the site. This requirement would mean that any proposed test site be previously equipped with a DIGA system, or that it must be possible to install and operate such a system at the test site. Obviously, from the project cost standpoint, the former is preferable; however, should the selected boiler not possess the necessary monitoring capabilities, it will be necessary to install and operate the required DIGA unit prior to any testing of the SFCS.

Finally, the proposed test site should be easily accessible to the program team, both physically and with respect to management cooperation. Physically, an ideal site should be located as near as possible (less than two hours travel time) to an EDC field office or equivalent. This would facilitate equipment delivery to the site and maintenance at the site, as well as eliminating high travel and lodging costs for project personnel.

The second requirement, management cooperation, is also very important. Management should be receptive to the proposed program and be willing to enter into it as a voluntary participant. Management support includes the availability of a reliable boiler (i.e., one with a minimal history of downtime) on which to perform the demonstration. The test boiler should be available for testing on relatively short (approximately one week) notice from program personnel. Some technical support (for plumbing, electrical connections, etc.) will also be required from the host company.

3.3 TASK 3 - DEMONSTRATION SITE SELECTION

The primary objective of this task is the final selection of a suitable test site, based on: (1) the criteria developed in the previous task, (2) the successful completion of preliminary boiler evaluation tests, and (3) negotiation with the host company, resulting in a mutually satisfactory test strategy.

The task will begin with a search to produce a list of candidate demonstration sites. Some background work will need to be done to make an informed assessment concerning the extent to which the proposed sites are typical of industrial installations. Exploratory discussions will then be conducted with the appropriate managers of the candidate locations. Following these discussions, onsite inspections of the installations will commence. This will involve a detailed examination of the physical plant including:

- Inspection of the boiler itself to ensure suitable optical access to the flame and to determine the practicality of mounting the SFA units to the boiler face, noting any modifications that need to be made and the extent of such changes
- Inspection of the stack configuration to determine the work required to install a DIGA system at the site (if one is not already present)

- A check of the closed-loop O_2 and other controls at the site, and a determination of their sensitivity
- Inspection of coal and air-feed systems (particularly secondary air), and a determination of control sensitivity on these systems
- In-depth discussions with plant management and personnel involving plant history, availability, and interest in the proposed project.

The ability to obtain a proper sighting of the flame through existing viewing ports is particularly important. The angle of sighting is crucial to proper SFA operation and thus to the system as a whole. Proper sighting geometry is basically dependent on the shape of the flame. Optimum SFA results occur when the sighting is near the periphery of the flame. Therefore, the boiler selected must possess flame viewing ports (or the possibility of creating such ports), and boiler geometry consistent with this requirement.

With proper viewing angle, SFA output varies significantly with load and fuel/air ratio. This substantial variation in SFA output is needed for proper closed loop operation of the SFCS. For any given proposed demonstration site, the only practical method of determining whether the boiler possesses adequate viewing geometry is to actually install an SFA unit on the boiler and record the output of the unit under various conditions of load and fuel/air ratios. The presence of a DIGA instack system is not necessary during this testing phase.

Following the preliminary onsite inspection, one or more sites will be chosen for the installation and testing of one SFA unit. This unit will be installed on a temporary basis and will be used to further determine the site's qualifications for the final demonstration of the SFCS. Program personnel will witness closed-loop boiler operation by the existing control system to verify that a basic control capability already exists.

The applications engineering effort mentioned above will proceed in parallel at an off-site location. This experimental effort will establish whether to vary the coal feed rate or the air feed rate to provide combustion control at a particular burner. The work may require the use of a consultant with access to a single-burner test boiler. Such facilities are readily available. This applications engineering activity will also focus on optimization of the installation geometry when a promising candidate boiler has been identified. Control sensitivity can be strongly influenced by sight paths, relative instrument/flame positions, etc. Site-specific installation geometry tests are, therefore, necessary.

Negotiation of a mutually satisfactory demonstration test plan with the owner of the candidate boiler is the last step that must be completed before the selection of the demonstration site can be finalized. This plan will include a bill of particulars and a time schedule of all activities related to the demonstration testing including: (1) boiler modifications, if any, to provide proper sighting and installation of the SFA, (2) installation of the SFA cooling and purging systems, (3) installation of secondary air control apparatus and, if necessary, fuel feed monitoring devices, (4) installation of an EDC DIGA monitoring system if one is not present, or modification of an existing unit, and (5) definition of types of testing to be undertaken, including fuel to be used, load limits, and ranges available during test periods. The program plan will be as specific as possible but flexible enough to accommodate unexpected situations, such as boiler failure, changes in plant operations, or equipment malfunction. Every precaution will be taken to prevent unscheduled disruption of plant operations.

3.4 TASK 4 - BASELINE OPERATING DATA

This task is intended to determine the characteristics of the test boiler when operating without the SFCS. The data acquired in this task will serve as a basis of comparison with the performance data to be obtained in Tasks 8 and 9, after the SFCS has been installed, to determine the gain in boiler efficiency realized by the use of the SFCS.

The tests in this task will be performed in accordance with the requirements of the Abbreviated Efficiency Test of the ASME Power Test Code (PTC No. 4.1 - 1964 with addenda 1968 and 1969). A copy of the ASME Test Form is given in Appendix B. Time-averaged data will be gathered over a range of operating conditions. In addition, coal type and cost will be noted for the subsequent determination of fuel savings in Task 2.

3.5 TASK 5 - CONTROL ENGINEERING

This task involves precisely defining each of the interfaces between the test boiler control system, the EDC control system, and the EDC sensors. This will establish the control strategy to be used and the manner in which it will be implemented, determine the modifications, if any, that need to be made in the existing control hardware, and identify the interfacing control elements that need to be purchased.

3.6 TASK 6 - EQUIPMENT SELECTION AND PROCUREMENT

This task consists of selecting and procuring all the hardware required for the demonstration tests.

The heart of the SFCS is the EDC Spectral Flame Analyzer (see Appendix A). Eight SFA's will be required. This will provide one analyzer per burner plus two to four backups (depending on the type of test boiler selected) to handle contingencies. It would appear that the most economical way to provide the required SFA's is to recondition and use the four SFA's fabricated by EDC for the Kerr-McGee project in Trona, California. These SFA's are the property of DOE. The remaining four SFA's required would be new units fabricated by EDC specifically for this demonstration program.

As previously stated, an EDC Stack Gas Analyzer will be required. This DIGA system must be capable of determining opacity and measuring concentrations of CO, NO, SO₂, and CO₂. Again, in the interest of cost control, the most economical way to proceed is to recondition the Stack Gas

Analyzer presently in use at the Kerr-McGee plant. This analyzer is also DOE property. In this particular case, the Stack Gas Analyzer at Kerr-McGee should also be upgraded to incorporate design improvements introduced by EDC during the past two years, including an EDC zero pipe assembly. This innovation makes it possible to regularly check the system zero and range.

The final group of equipment that must be specified and purchased under this task is the control hardware. Included are the air control valves, summers, manual/automatic stations, time proportional controllers, and data loggers. It is impossible to state precisely which control components will be required until an actual demonstration boiler has been selected. However, a typical SFCS control system is shown in Figure 3.1 for purposes of illustration.

3.7 TASK 7 - INSTALLATION AND STARTUP

This task consists of installing the aforementioned hardware and ensuring proper operation. Elements of this task include site preparation, boiler modifications, SFA installation, Stack Gas Analyzer installation, and control system modification.

Boiler modifications may include changes in existing viewing ports to accommodate the SFA's, or fabrication of new viewing ports. Permanent mounting structures for the SFA modules and their associated hardware must be installed, including cooling systems and power and output cables.

The control and monitoring equipment associated with the SFA's will be installed in the boiler control room. At least two days of testing will be necessary to thoroughly check out the equipment while the test boiler is operating under variable load conditions. During this period, all necessary modifications will be made to the SFA alignment, monitoring equipment, interfaces, and recorders.

If the selected demonstration site is not equipped with an EDC Stack Gas Analyzer, it will be necessary to install the DIGA system concurrently with the above effort. This will involve:

- Fitting the stack with an 8-inch, cross-stack instrument pipe and its accompanying 9-inch zero pipe
- Installing all auxiliary hardware, such as instrument and source mounting flanges, purge air blowers, Rotron blowers, and the EDC zero mode activation system (a pneumatic device used to turn the zero pipe)
- Installing all instrument power input and data output cables
- Installing a DIGA monitoring and control console in the boiler control room
- Installing the instrument and source modules on the pipe
- Installing and checking all power/data hookups

Following optical alignment and electronic calibration, the DIGA system will also be tested for at least two days under normal boiler operating conditions.

Finally, it will be necessary to recheck the performance of the O_2 , secondary air, and fuel control systems, and to verify that all the sensors and control hardware are functioning properly before proceeding with the open- and closed-loop testing.

3.8 TASK 8 - OPEN-LOOP PERFORMANCE TESTING

The purpose of the open-loop tests is to characterize the SFCS output control signals as a function of boiler load. In addition, the tests will characterize the performance of individual burners and will make it possible for the test group to identify the burners that need maintenance or attention before the closed-loop demonstration takes place. The open-loop phase is also useful in that it is basically a "shakedown cruise" of the system. One

of the main goals of the open-loop tests will be to determine the presence of any abnormalities or problems in the test systems. If this situation arises, the necessary control loop modifications will be implemented within this task.

Open-loop testing will involve external manipulations of the boiler load, excess O_2 , and secondary air flow. The SFA and DIGA output data obtained in these tests will help determine the system output limits to be used in the closed-loop demonstration phase. For this reason, the open-loop test phase is expected to be long in duration, lasting approximately four to five weeks.

3.9 TASK 9 - CLOSED-LOOP PERFORMANCE TESTING

The closed-loop tests will be identical to the open-loop tests except in one respect: during the closed-loop tests, the boiler will be on automatic control via the SFCS. The main variables will again be secondary air and boiler load. The ability of the SFCS to adapt to load changes and the control capability of the SFCS will be demonstrated. This task will also last four to five weeks and will generate ample data on emissions, excess air, and fuel consumption and costs for the technical and economic analyses that comprise the last two program tasks. The tests could also provide useful information for the development of more efficient coal combustion.

3.10 TASK 10 - TECHNICAL ANALYSIS

This task involves the preparation of a complete technical analysis of the boiler combustion control system installed and demonstrated under this program. This analysis will include an assessment of both the underlying concept and the particular physical embodiment of that concept developed under this program. The implementation portion of this assessment will first cover each system component, addressing issues such as reliability and temperature sensitivity. Subsequently, the implementation assessment will deal with the entire system.

This Technical Analysis will also include recommendations regarding possible future work and/or applications for EDC's combustion control technology.

3.11 TASK 11 - ENERGY SAVINGS ANALYSIS

This task will consist of three separate analyses. The first will determine the energy savings actually achieved at the host facility. This determination will be based on the differences in boiler performance with and without EDC's SFCS, using the ASME testing procedure.

The second analysis will estimate the national energy savings that could be achieved if all suitable coal-fired boilers in the United States were equipped with combustion control systems of the type demonstrated within this program.

The third and final analysis will estimate the national energy savings that could be realized via this technology, not only in existing coal-fired boilers, but also in the new coal-fired units projected to come into service by 1990.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

4. PROGRAM MANAGEMENT AND SCHEDULE

The program management structure and schedule are shown in Figures 4.1 and 4.2 respectively. Month 1 of the schedule corresponds to October 1979. The program schedule includes the division of labor between EDC and Thermo Electron. No changes in the schedule are anticipated at this time.

Figure 4.1 Program Structure

Figure 4.2 Program Schedule

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

APPENDIX A

TECHNOLOGY DESCRIPTION

A.1 SPECTRAL FUEL CONSERVATION SYSTEM

EDC's Spectral Fuel Conservation System (SFCS) is a unique, sophisticated flame monitoring instrument system capable of reducing fuel consumption. Balanced boiler operation is achieved by directly measuring and controlling the local stoichiometry at each burner.

A complete SFCS is illustrated in Figure A.1. The particular boiler shown in this figure is a front- and rear-fired boiler with Spectral Flame Analyzers (SFA's) mounted on all burners, front and rear. The SFCS consists of three discrete, yet integrated, subsystems:

- Spectral Flame Analyzers - The SFA's are the heart of the EDC system. They continuously monitor the quality of combustion.
- Instack Pollution Monitor - This instack instrument measures the concentrations of important pollutants such as CO, NO, SO₂, CO₂, and opacity.
- Control Subsystem - The control subsystem provides an interface between the existing boiler controls and the aforementioned analyzers. Output signals from the SFA's and the stack monitor provide the input control signals.

Each of these subsystems is described in greater detail in the subsections that follow.

The SFCS has been designed to simultaneously:

- minimize the excess air level
- maximize combustion efficiency for all loads and air/fuel ratio changes
- minimize fan power requirements
- provide continuous correction of marginal or defective burners
- provide continuous correction of windbox imbalances

SPECTRAL FUEL CONSERVATION SYSTEM

Figure A.1 Spectral Fuel Conservation System
(Environmental Data Corporation)

- precisely control biased firing
- reduce SO_3 formation and the resultant equipment corrosion problems
- reduce NO_x generation by reducing peak flame temperature
- improve defense mechanisms against slagging and fouling

The principal benefits of the SFCS are as follows:

- Greater Economy - The ability to operate a boiler closer to the theoretical zero-excess-air level results in important fuel savings. Fuel savings alone are expected to provide a 1- to 2-year pay-back on the cost of an installed system. In some instances the results may be even more dramatic, as was the case in an installation at Canal Electric Company in Sandwich, Massachusetts where a \$30,000 CO sensor system resulted in an annual fuel saving of approximately \$1,000,000.
- Reduced Maintenance - A high level of excess air increases the production of undesirable gases such as sulfur trioxide (SO_3), which combines with water vapor to form sulfuric acid. This is, of course, highly corrosive to the interior of the boiler and all associated equipment. Reduced production of corrosive combustion byproducts as a result of low-excess-air firing will permit longer intervals between routine periodic shutdowns for major maintenance.

Also, slagging and fouling, two primary causes of boiler maintenance problems, can be controlled more easily with the EDC system. The ability to balance burner operations provides the capability to control excess air levels more precisely, which, in turn, provides a mechanism to control (within limits) flame temperature, which determines the physical state of the inorganic coal components. Similarly, the propensity for fouling is a direct function of soot formation rates, which depend to a large extent on the air-to-fuel ratios at each burner; this will be controlled by the proposed system.

- Increased Capacity - Optimizing power generation per unit of fuel consumed has the effect of increasing the capacity of a power generating unit. Also, as already noted, lower-excess-air levels will reduce NO_x production. Since some boilers now run at partial capacity to remain within NO_x regulatory limits, the SFCS will permit increased output from these installations. This is expected to be especially significant at certain electric utilities now facing capacity limitations because of an inability to build new plants in a timely fashion.

A.2 SPECTRAL FLAME ANALYZER

The heart of the SFCS is the SFA (Spectral Flame Analyzer), a device developed by EDC using Company funds. The SFA mounts on the front of a burner and, in some cases, may utilize the viewing port normally used by the flame-proving device present on most industrial boilers. The SFA gathers light from the portion of the flame immediately in front of the burner. The optical system provides a limited field of view so that any one analyzer can see only one flame. Output is not affected by nearby flames.

The SFA utilizes the principles of flame emission spectroscopy. The intensity of the light emitted by the flame is measured repeatedly at multiple wavelengths. The primary wavelength is selected to coincide with a specific infrared emission of a luminous, universal combustion species. This species was identified by EDC scientists by performing high-resolution spectral scans of flames over a variety of air/fuel ratios, boiler loads, and fuel types. The secondary intensity measurement is made at a nearby wavelength where these combustion species do not emit radiation. The two measured intensities are ratioed electronically to form the output signal, as shown schematically in Figure A.2. An SFA, therefore, utilizes high-resolution wavelength selection and the ratioing of emitted radiation at multiple closely spaced wavelengths to provide a very unique capability.

Figure A.2 Spectral Flame Analyzer
(Environmental Data Corporation)

The emission intensities at the primary and secondary wavelengths, as measured by the SFA, are affected equally by the operating anomalies that inevitably complicate the measurement task. Such anomalies include obscuration, boiler opacity (i.e., coal dust, dirty windows, etc.), flame flicker, etc. As long as the intensity at each wavelength is reduced by the same percentage, the ratio of the two will be unaffected. This has been verified experimentally by EDC scientists. The only factor affecting SFA output is the strength of the emitting combustion species (i.e., the local stoichiometry). Also, this instrumentation is largely unaffected by thermally emitting surfaces, such as hot boiler tubes and walls, because hot emissive surfaces do not contain significant amounts of the quantized energy characteristic of a flame. Finally, the analytical method outlined here is completely independent of gross flame emission intensity. A sudden blanket of dust that dramatically reduces the overall observed flame intensity does not affect the SFA output signal.

SFA output varies with the percentage of theoretical air in the combustion process. The calibration curve from one test, in which the percentage of theoretical air varied from 88 percent to 128 percent of theoretical, is shown in Figure A.3. These data were obtained by EDC from tests performed on a 45-MW combustion engineering boiler owned by the City of Pasadena Water and Power Authority. The size of this installation is typical of large, multiburner, steam-raising units in industry. During the testing, the baseline emission intensity remained constant while the emission intensity of the chosen species at the primary wavelength varied linearly with the percentages of theoretical air. SFA's have been tested on both oil and gas fuel firing, and also on a mixture of pulverized coal and various gases. Response curves of the coal/gas mixture were similar to the curve in Figure A.3, which was obtained using No. 2 oil as the boiler fuel.

In summary, EDC's SFA offers the following features:

- Sensitive to only one emitting species - a species whose concentration varies linearly with the percentage of theoretical air

Fuel Type: No. 2 Oil

Figure A.3 Calibration Curve of Spectral Flame Analyzer; Signal Output vs. Percent Theoretical Air

- Independent of boiler load changes
- Independent of window obscuration
- Independent of other emissions, such as hot boiler tubes and walls
- One- or two-second response time
- Insensitive to flue gas dust concentration

A.3 INSTACK GAS EMISSION MONITOR

The measurement principle employed in the EDC Stack Gas Monitor is absorption spectroscopy rather than the emission spectroscopy used with the SFA. A light beam is directed through the gas stream from one side of the stack to the other, and the absorption of this light at particular wavelengths after it passes through the gas stream is measured. A schematic representation of this configuration appears in Figure A.4. The light source may provide radiation in the infrared, ultra-violet, or visible portions of the electromagnetic spectrum, depending on the target species. Each gas of interest has a particular pattern or "signature" of absorption at specific wavelengths in these spectral regions. The signatures of various gases may partially overlap; therefore, for clarity of analysis, particular spectral lines (wavelengths) are selected for each gas in such a way that there is no effective overlap with other gases that may be present. The signal detection system is tailored to reject unwanted information and to measure precisely the intensity of the particular wavelengths chosen for analysis of a specific gas.

The intensity of the light seen by the detectors in the Stack Gas Monitor will be affected by a number of factors, including the presence of dust or other particulate matter within the gas stream, changes in intensity of the light source itself, changes in detector sensitivity, and dirt adhering to the surface of the windows. To make the system output insensitive to these spurious intensity variations, the Stack Gas Monitor employs a dual-wavelength ratioing technique similar to that already described for the SFA.

Overall View

Instrument Box Airflow

Figure A.4 EDC Stack Gas Analyzer

The EDC Stack Monitor offers a number of features that have given it a position of industry leadership. Among these is the concept, which EDC pioneered, of performing the measurement with an instrument that measures across the entire gas stream.

Historically, measurements had been made by extracting a sample from the gas stream and analyzing it in a separate instrument. This sampling, or extractive technique leads to substantial inaccuracies where the gas flow is stratified and not well mixed, as is frequently the case in an operating situation. In this event, the sample will not be representative of the whole. Sampling systems have a further disadvantage in that they normally require cleanup of the sample prior to measurement; i.e., removal of water vapor, particulate matter, and condensibles. Cleanup systems are typically demanding of maintenance attention to ensure that the sample reaching the analyzer is truly representative of the gas that was drawn off from the stack.

Extractive systems are also inherently slow in operation, whereas the instack spectroscopic system responds essentially instantaneously to changes in the gas stream, which is important due to the speed with which boiler load can change or fuel mixture variations can occur.

The EDC monitoring system has all parts of the system external to the gas stream, so that the equipment is unaffected by moisture or the corrosive effect of certain gases, and is relatively immune to soot, smoke, and other particulates in the stream. An air curtain produced by an integral blower serves as an interface between the system windows and the gas stream, and effectively insulates the system from direct contact with the gas stream.

The stack monitor is a commercial product sold and serviced by EDC. EDC presently has more than 1200 analyzer modules in operation around the world. They are installed on utility and industrial boiler stacks and process stream ducts to monitor pollution emission compliance and to control combustion.

A.4 CONTROL SUBSYSTEM

The Control Subsystem is designed and assembled in accordance with standard industry practice. Components consist of standard commercial items from control hardware suppliers. An all-analog system is proposed since, in all likelihood, the host plant will have analog controls. An alternative plan for a host with direct digital control (DDC) would involve less new control hardware but some investment in control software changes.

In a manually operated system (open-loop), the data from the SFA's and from the CO Stack Monitor will be suitably displayed for the boiler operator, who will adjust the burners and overall air control in order to achieve the best degree of balance and the lowest level of excess air. A closed-loop system, on the other hand, will process the data and utilize the output signals to adjust automatically the individual burners and the overall boiler excess air.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

APPENDIX B

SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a(1964)

TEST NO.		BOILER NO.		DATE	
OWNER OF PLANT		LOCATION			
TEST CONDUCTED BY		OBJECTIVE OF TEST		DURATION	
BOILER MAKE & TYPE		RATED CAPACITY			
STOKER TYPE & SIZE		BURNER, TYPE & SIZE			
PULVERIZER, TYPE & SIZE		STATE		SIZE AS FIRED	
FUEL USED		MINE		COUNTY	
PRESSURES & TEMPERATURES					
1	STEAM PRESSURE IN BOILER DRUM	psia		COAL AS FIRED PROX. ANALYSIS	
2	STEAM PRESSURE AT S. H. OUTLET	psia		37	MOISTURE
3	STEAM PRESSURE AT R. H. INLET	psia		38	VOL MATTER
4	STEAM PRESSURE AT R. H. OUTLET	psia		39	FIXED CARBON
5	STEAM TEMPERATURE AT S. H. OUTLET	F		40	ASH
6	STEAM TEMPERATURE AT R. H. INLET	F		TOTAL	
7	STEAM TEMPERATURE AT R. H. OUTLET	F		41	Btu per lb AS FIRED
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F		42	ASH SOFT TEMP. ASTM METHOD
9	STEAM QUALITY % MOISTURE OR P. P. M.			COAL OR OIL AS FIRED ULTIMATE ANALYSIS	
10	AIR TEMP. AROUND BOILER (AMBIENT)	F		43	CARBON
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F		44	HYDROGEN
12	TEMPERATURE OF FUEL	F		45	OXYGEN
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F		46	NITROGEN
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F		47	SULPHUR
FUEL DATA					
			48	ASH	
			49	MOISTURE	
			50	FINENESS % THRU 50 M*	
			51	FLASH POINT F*	
			52	Sp. Gravity Deg. API*	
			53	VISCOSITY AT SSU* BURNER SSF	
			54	TOTAL HYDROGEN % wt	
			55	Btu per lb	
			56	CH ₄ METHANE	
			57	C ₂ H ₂ ACETYLENE	
			58	C ₂ H ₄ ETHYLENE	
			59	C ₂ H ₆ ETHANE	
			60	H ₂ S	
			61	CO ₂	
			62	H ₂ HYDROGEN	
UNIT QUANTITIES					
15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb		37	MOISTURE
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb		TOTAL	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb		COAL PULVERIZATION	
18	ENTHALPY OF REHEATED STEAM R. H. INLET	Btu/lb		48	GRINDABILITY INDEX*
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb		49	FINENESS % THRU 50 M*
20	HEAT ABS. LB OF STEAM (ITEM 16 - ITEM 17)	Btu/lb		50	FINENESS % THRU 200 M*
21	HEAT ABS. LB R. H. STEAM (ITEM 19 - ITEM 18)	Btu/lb		64	INPUT-OUTPUT EFFICIENCY OF UNIT %
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb		HEAT LOSS EFFICIENCY	
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb		65	HEAT LOSS DUE TO DRY GAS
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb		66	HEAT LOSS DUE TO MOISTURE IN FUEL
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb		67	HEAT LOSS DUE TO H ₂ O FROM COMB. OF H ₂
HOURLY QUANTITIES					
26	ACTUAL WATER EVAPORATED	lb/hr		68	HEAT LOSS DUE TO COMBUST. IN REFUSE
27	REHEAT STEAM FLOW	lb/hr		69	HEAT LOSS DUE TO RADIATION
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr		70	UNMEASURED LOSSES
29	TOTAL HEAT INPUT (Item 28 x Item 41) / 1000	kB/hr		71	TOTAL
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr		72	EFFICIENCY = (100 - Item 71)
31	TOTAL HEAT (Item 26 + Item 20) + (Item 27 + Item 21) + Item 30 / 1000	kB/hr			
FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET					
32	CO ₂	% VOL			
33	O ₂	% VOL			
34	CO	% VOL			
35	N ₂ (BY DIFFERENCE)	% VOL			
36	EXCESS AIR	%			

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

Figure B.1

CALCULATION SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT		TEST NO.	BOILER NO.	DATE			
30	HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR x		$\frac{\text{ITEM 16} - \text{ITEM 17}}{1000}$	kB/hr			
24	<p>If impractical to weigh refuse, this item can be estimated as follows</p> <p>DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\% \text{ ASH IN AS FIRED COAL}}{100 - \% \text{ COMB. IN REFUSE SAMPLE}}$</p> <p>CARBON BURNED PER LB AS FIRED FUEL = $\frac{\text{ITEM 43}}{100} - \left[\frac{\text{ITEM 22} \times \text{ITEM 23}}{14,500} \right] = \dots\dots\dots$</p>		<p>NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.</p>				
25	<p>DRY GAS PER LB AS FIRED FUEL = $\frac{11\text{CO}_2 + 8\text{O}_2 + 7(\text{N}_2 + \text{CO})}{3(\text{CO}_2 + \text{CO})} \times (\text{LB CARBON BURNED PER LB AS FIRED FUEL} + \frac{3}{8} \text{ S})$</p> <p>= $11 \times \frac{\text{ITEM 32}}{\dots\dots\dots} + 8 \times \frac{\text{ITEM 33}}{\dots\dots\dots} + 7 \left(\frac{\text{ITEM 35}}{\dots\dots\dots} + \frac{\text{ITEM 34}}{\dots\dots\dots} \right) \times \left[\frac{\text{ITEM 24}}{\dots\dots\dots} + \frac{\text{ITEM 47}}{267} \right] = \dots\dots\dots$</p>						
36	<p>EXCESS AIR = $100 \times \frac{\text{O}_2 - \frac{\text{CO}}{2}}{.2682\text{N}_2 - (\text{O}_2 - \frac{\text{CO}}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})} = \dots\dots\dots$</p>						
HEAT LOSS EFFICIENCY				Btu/lb AS FIRED FUEL	LOSS $\frac{\text{HHV}}{100} \times$	LOSS %	
65	HEAT LOSS DUE TO DRY GAS = $\text{LB DRY GAS PER LB AS FIRED FUEL} \times C_p \times (t_{\text{vg}} - t_{\text{air}}) = \frac{\text{ITEM 25}}{\dots\dots\dots} \times 0.24 \times (\text{ITEM 13}) - (\text{ITEM 11}) = \dots\dots\dots$					$\frac{65}{41} \times 100 =$	
66	HEAT LOSS DUE TO MOISTURE IN FUEL = $\text{LB H}_2\text{O PER LB AS FIRED FUEL} \times [(\text{ENTHALPY OF VAPOR AT 1 PSIA \& T GAS LVG}) - (\text{ENTHALPY OF LIQUID AT T AIR})] = \frac{\text{ITEM 37}}{100} \times [(\text{ENTHALPY OF VAPOR AT 1 PSIA \& T ITEM 13}) - (\text{ENTHALPY OF LIQUID AT T ITEM 11})] = \dots\dots\dots$					$\frac{66}{41} \times 100 =$	
67	HEAT LOSS DUE TO H ₂ O FROM COMB. OF H ₂ = $9\text{H}_2 \times [(\text{ENTHALPY OF VAPOR AT 1 PSIA \& T GAS LVG}) - (\text{ENTHALPY OF LIQUID AT T AIR})] = 9 \times \frac{\text{ITEM 44}}{100} \times [(\text{ENTHALPY OF VAPOR AT 1 PSIA \& T ITEM 13}) - (\text{ENTHALPY OF LIQUID AT T ITEM 11})] = \dots\dots\dots$					$\frac{67}{41} \times 100 =$	
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = $\frac{\text{ITEM 22}}{\dots\dots\dots} \times \frac{\text{ITEM 23}}{\dots\dots\dots} = \dots\dots\dots$					$\frac{68}{41} \times 100 =$	
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL}} = \frac{\text{ITEM 28}}{\dots\dots\dots}$					$\frac{69}{41} \times 100 =$	
70	UNMEASURED LOSSES**					$\frac{70}{41} \times 100 =$	
71	TOTAL						
72	EFFICIENCY = $(100 - \text{ITEM 71})$						

* For rigorous determination of excess air see Appendix 9.2 - PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may be provided for by assigning a mutually agreed upon value for Item 70.

Figure B.2