# PUBLIC DESIGN REPORT

## (Final Report Volume 1: Public Design)

# PULSE COMBUSTOR DESIGN QUALIFICATION TEST AND CLEAN COAL FEEDSTOCK TEST

**PREPARED FOR:**

U.S. Department of Energy
National Energy Technology Laboratory
(Under Cooperative Agreement No. DE-FC22-92PC92644)

**PREPARED BY:**

ThermoChem, Inc.
6001 Chemical Road
Baltimore, Maryland 21226

**Date Prepared: June 15, 2001**

**Date Issued of First Draft: August 17, 2001**

**Date Issued of Second Draft: November 30, 2001**

**Date Issued of Final: February 8, 2002**

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## FORWARD

This work was performed under Cooperative Agreement No. DE-FC22-92PC92644 between the United States Department of Energy and ThermoChem, Inc. The work was carried out by ThermoChem, Inc. (TCI) at its development testing and manufacturing facilities located at 6001 Chemical Road, Baltimore, Maryland 21226. Participants associated with this project are given below:

ThermoChem, Inc.

Project Manager/Chief Engineer – W. G. Steedman
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 43
Fax: (410) 354-9894
E-mail: wsteedman@tchem.net

ThermoChem Business Official

Vice President – L. Rockvam
ThermoChem, Inc.
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

U.S. Department of Energy

Project Manager – Leo E. Makovsky
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, Pennsylvania 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

# <u>ABSTRACT</u>

For this Cooperative Agreement, the pulse heater module is the technology envelope for an indirectly heated steam reformer. The field of use of the steam reformer pursuant to this Cooperative Agreement with DOE is for the processing of sub-bituminous coals and lignite. The main focus is the mild gasification of such coals for the generation of both fuel gas and char – for the steel industry is the main focus. An alternate market application for the substitution of metallurgical coke is also presented.

This project was devoted to qualification of a 253-tube pulse heater module. This module was designed, fabricated, installed, instrumented and tested in a fluidized bed test facility. Several test campaigns were conducted. This larger heater is a 3.5 times scale-up of the previous pulse heaters that had 72 tubes each. The smaller heater has been part of previous pilot field testing of the steam reformer at New Bern, North Carolina.

The project also included collection and reduction of mild gasification process data from operation of the process development unit (PDU). The operation of the PDU was aimed at conditions required to produce char (and gas) for the Northshore Steel Operations. Northshore Steel supplied the coal for the process unit tests.

## ACKNOWLEDGEMENTS

ThermoChem wishes to acknowledge the contributions of the DOE Project Managers on this project namely, Mr. William Mundorf, Mr. Art Baldwin, the late Mr. Steve Heinz, Mr. Bob Kornosky, Mr. Mike Eastman, Mr. Doug Gyorke, Dr. Tom Sarkas, Mr. Gary Stats and Mr. Leo Makovsky. ThermoChem also wishes to acknowledge the contribution of our cost sharing partners during the course of this project, namely Mr. Denny Hunter of the Weyerhaeuser Paper Company, Mr. Lance Ahearn of the Heartland Development Corporation, and Mr. Frank Tenore of ThermoChem Recovery International (TRI). Furthermore, ThermoChem also acknowledges the contributions of Mr. Jack Siegel of Energy Resources International, Mr. Dan Burciaga of Industra and the support by Javan and Walters Engineering Group.

## POINT OF CONTACT

ThermoChem, Inc.

Leland Rockvam
Vice President
ThermoChem, Inc.
6001 Chemical Road
Baltimore, MD 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

DOE

Leo E. Makovsky
Project Manager
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, PA 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

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## LIST OF ABBREVIATIONS

| | | |
|---|---|---|
| ACFM | --- | Actual Cubic Feet per Minute |
| ASME | --- | The American Society of Mechanical Engineers |
| BMCS | --- | Burner Management Control System |
| BMS | --- | Burner Management System |
| BOD | --- | Biological Oxygen Demand |
| BTU | --- | British Thermal Unit |
| C | --- | Celsius |
| CCT | --- | Clean Coal Technology |
| COD | --- | Chemical Oxygen Demand |
| DOE | --- | Department of Energy |
| DRI | --- | Direct Reduction of Iron |
| EIA | --- | Environmental Impact Assessment |
| EPA | --- | Environmental Protection Agency |
| EPC | --- | Engineering Procurement Construction |
| F | --- | Fahrenheit |
| FFT | --- | Fast Fourier Transform |
| FGD | --- | Flue Gas Desulfurization |
| FGR | --- | Flue Gas Recirculation |
| FR | --- | Firing Rate |
| G&A | --- | Government & |
| GC | --- | Gas Chromatograph |
| GHG | --- | Greenhouse Gas |
| GPM | --- | Gallons Per Minute |
| GRI | --- | Gas Research Institute |
| GW | -- | Gigawatts |
| HRSG | --- | Heat Recovery Steam Generator |
| Hz | --- | Helmholtz |
| IRR | --- | Internal Rate of Return |
| LPG | --- | Liquefied Petroleum Gas |
| MCC | --- | Motor Control Center |
| MTCI | --- | Manufacturing and Technology Conversion International, Inc. |
| MW | --- | Megawatt |
| NERC | --- | National Electric Reliability Council |
| NGCC | --- | Natural Gas Combined Cycle |
| NPCC | --- | New England |
| PC | --- | Pulse Combustor |
| PDU | --- | Process Development Unit |
| PFD | --- | Process Flow Diagram |
| P&ID | --- | Process & Instrumentation Diagrams |
| PLC | --- | Programmable Logic Controller |
| PSIG | --- | Pounds per Square Inch Gage |
| O&M | --- | Operation & Maintenance |
| R | --- | Reactor |

## LIST OF ABBREVIATIONS (Continued)

| | | |
|---|---|---|
| RDF | --- | Refuse Derived Fuel |
| RO | --- | Reverse Osmosis |
| ROI | --- | Return On Investment |
| SCR | --- | Selective Catalytic Reduction |
| SNCR | | Selective Non-Catalytic Reduction |
| SS | --- | Stainless Steel |
| SVOC | --- | Semi-Volatile Organic Compounds |
| TC | --- | Thermocouple |
| THC | --- | Total Hydrocarbons |
| TRI | --- | ThermoChem Recovery International, Inc. |
| VOC | --- | Volatile Organic Compounds |

## LIST OF UNITS

| | | |
|---|---|---|
| acfm | --- | Actual Cubic Feet per Minute |
| Btu | --- | British Thermal Unit |
| C | --- | Celsius |
| dia. | --- | Diameter |
| F | --- | Fahrenheit |
| ft | --- | Feet |
| gal | --- | Gallon |
| gpm | --- | Gallons Per Minute |
| GW | --- | Gigawatts |
| hp | --- | Horsepower |
| h | --- | Hour |
| Hz | --- | Hertz |
| kW | --- | Kilowatt |
| kWh | --- | Kilowatt-hour |
| lb | --- | Pound |
| MM | --- | Million |
| MW | --- | Megawatt |
| ppm | --- | Pounds per Minute |
| psig | --- | Pounds per Square Inch |
| scfm | --- | Square Cubic Feet per Minute |
| sq. ft. | --- | Square feet |

## GLOSSARY OF TERMS

C: Carbon

CO: Carbon Monoxide

$CO_2$: Carbon Dioxide

Coke: Coke is made by baking a blend of selected Bituminious coals (called Coking coal or Metallurgical Coal) in special high temperature ovens without contact with air until almost all of the volatile matter is driven off. Metallurgical coke provides the carbon and heat required to chemically reduce iron to molten pig iron (hot metal). For coke to have the proper physical properties to perform this function, it must be carbonized at temperatures between 900 and 1095°C. The most important physical property of metallurgical coke is its strength to withstand breakage and abrasion during handling and its use in the blast furnace. There are two traditional processes to manufacture metallurgical coke: beehive process and by-product process. Other processes are referred to as continuous processes. The most common process currently used is the by-product process.

$H_2S$: Hydrogen Sulfide

$NO_X$: Nitrogen Oxides

NaHS: Sodium Hydrasulfide

$O_2$: Oxygen

S: Sulfur

$SO_2$: Sulfur dioxide

THC: Total Hydrocarbons

## EXECUTIVE SUMMARY

### Brief Description of the Project

ThermoChem, Inc. and its affiliate, Manufacturing and Technology Conversion International, Inc. (MTCI), have developed the PulseEnhanced™ Steam Reforming Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled-up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications. ThermoChem, Inc. and its subsidiary, ThermoChem Recovery International, Inc. (TRI), are the project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project and has title to all equipment purchased or fabricated under the project.

The project includes two areas of emphasis: (i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and (ii) process characterization through coal feedstock tests in a Process Development Unit (PDU). The 61- and 72- tube heater bundles, which were previously demonstrated, are too small for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require 253-tube heater bundles. For example, a 7-heater (253-tube) reformer can mild gasify over 1,100 short tons of coal per day. If the smaller 72-tube heater modules were used, the reformer would require 25 installed units, each with its own fuel train, combustion air and flue gas connections.

### Project History

On October 27, 1992, the U.S. Department of Energy (DOE) and ThermoChem entered into a Cooperative Agreement for a Demonstration project under the Clean Coal IV solicitation. Preliminary design and engineering work was conducted for a series of potential sites for a demonstration facility, and a scaled-up 253-tube pulse heater bundle was designed and fabricated. On September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

Technology Being Employed

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost. The project has qualified the design of the 253-resonance tube pulse heater, which is the technology envelope and is the heart of a commercial-scale system.

Project Location

The project is located at ThermoChem's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor area within the Company premises, and the PDU is located indoors in the Company's Development and Manufacturing plant.

Status as of the Date of the Report

As of the date of the report, the Pulse Combustor Design Qualification Test Facility has been constructed and commissioned. Testing has been performed.

Summary of Test Program

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields and composition, char yields and composition and endothermic heat requirements were determined in the PDU.

## Project Costs

The total cost of this project was $8.6 million, with DOE providing fifty percent of this cost. A commercial-scale facility capable of processing 40 US tons per hour in a mild gasification mode is projected to have an installed capital cost of $28,184,000.

# 1.0 PROJECT OVERVIEW

## 1.1 Purpose of the Public Design Report

The purpose of the Public Design Report is to consolidate, for the purpose of public use, all design and cost information on the project at the completion of construction and startup. The report provides an overview of the project, the salient design features and data, and the role of the pulse combustor design qualification test project in commercialization planning.

## 1.2 Brief Description of the Project

ThermoChem, Inc. and its affiliate, MTCI, have developed the PulseEnhanced™ Steam Reforming Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications.

The project includes two areas of emphasis: (i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and (ii) process characterization through coal feedstock tests in a PDU. The 61- and 72-tube heater bundles, which were previously demonstrated, are too small for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require 253-tube heater bundles.

### 1.2.1 Project History

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September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

### 1.2.2 Project Sponsors

ThermoChem, Inc. and its subsidiary, TRI, are the revised project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project, and has title to all equipment purchased or fabricated under the project.

### 1.2.3 Technology Being Employed

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost. The project will qualify the design of the 253-resonant tube pulse heater, which is the technology envelope and the heart of a commercial-scale system.

### 1.2.4 Technology Vendors

ThermoChem is the principal technology vendor, supported by MTCI. MTCI is the developer of the PulseEnhanced™ Steam Reformer and owns the patent rights. ThermoChem has exclusive license rights to applications of the technology for the processing of coal.

### 1.2.5 Performance Requirements

The primary scale-up issues for the 253-tube full-scale pulse combustor are the uniformity of the distribution of flue gas through the 253-resonance tubes, uniformity of tube skin temperature in a transverse plane and the achievement of sufficient level of dynamic pressure amplitude in the combustion chamber to provide a reasonably high film side heat transfer profile along the resonance tube length.

The secondary issues involve combustion process modification and optimization in the traditional trade-off between $NO_X$ /CO/THC emissions. The later is mostly driven by site specific environmental requirements in the context of combustor maximum firing rate and maximum turndown, etc. The variables available to accommodate the needs of a specific application include air/fuel ratio (particularly with reburn being part of the overall system configuration), fuel injection modifications and flue gas recycle (FGR).

The fuel gas distribution to each of the aerodynamic valves must be sufficiently uniform in the entire range of firing to maintain robust combustion-induced oscillations in the pulse combustor and to ensure uniform flue gas distribution in the resonance tubes.

Qualification of the design of the 253-tube heater bundle will enable ThermoChem to meet the overall system performance requirements for commercial use. Process fluid mechanics, heat transfer, mass transfer, and mixing must be preserved in the scale-up in order to achieve equal or greater system performance. For example, the combustion chamber aspect ratio (height-to-diameter) decreases with an increase in pulse heater module size due to acoustic and geometric considerations. This reduced aspect ratio could affect lateral mixing of the fuel and air, temperature uniformity in the heat exchanger tubes, and proper mass flow distribution of the flue gas between the resonance tubes. In addition, the scaled-up heater must be designed to achieve heat addition that is substantially in phase with pressure oscillations. Appropriate controls and instrumentation must be also used to demonstrate to ThermoChem's clients, Engineering, Procurement and Construction (EPC) partners and bonding insurance companies the efficacy of the technology in the full-scale commercial applications. Without such an efficacy and design qualification, the clients, the EPC partners and bonding insurance companies will not provide the mechanical and process warranties for commercial projects employing the technology.

The production of char for use in direct reduction of iron (DRI) continues to be one of the attractive early commercial applications of the technology. In this application, the char is a direct substitute for metallurgical coke. The char produced via mild gasification easily satisfies the purity requirements of the DRI Process. The strength requirements for coke used in conventional blast furnace operations are not relevant to the DRI process. This is the basis for selecting the coal to be tested in the PDU. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant in DRI process.

Petroleum coke, which can be used as a DRI reductant, has the following specifications:

0.5% Sulfur
90% Fixed Carbon
5-10% Volatiles

A coal-derived char should surpass these specifications in order to be more attractive than petroleum coke. The specifications provided by Northshore Mining for the char are:

0.3% Sulfur
85% Fixed Carbon

Volatile content is not important to Northshore. However, the target of 85% fixed carbon, will render the volatile content to be fairly low.

#### 1.2.6 Project Block Flow Diagram

Figure 1-1 presents the project block flow diagram for the combustor design qualification test facility

Sand is used as the fluid bed medium. The sand is fluidized with air from five-rental diesel compressors (stream no. 1). Water (stream no. 2) is injected into the bed to impose a heat load on the system to maintain the desired bed temperature. The fluidized bed off-gas (stream no. 3), comprising air used for fluidization and steam generated in the fluid-bed, passes through a cyclone for particulate collection before it

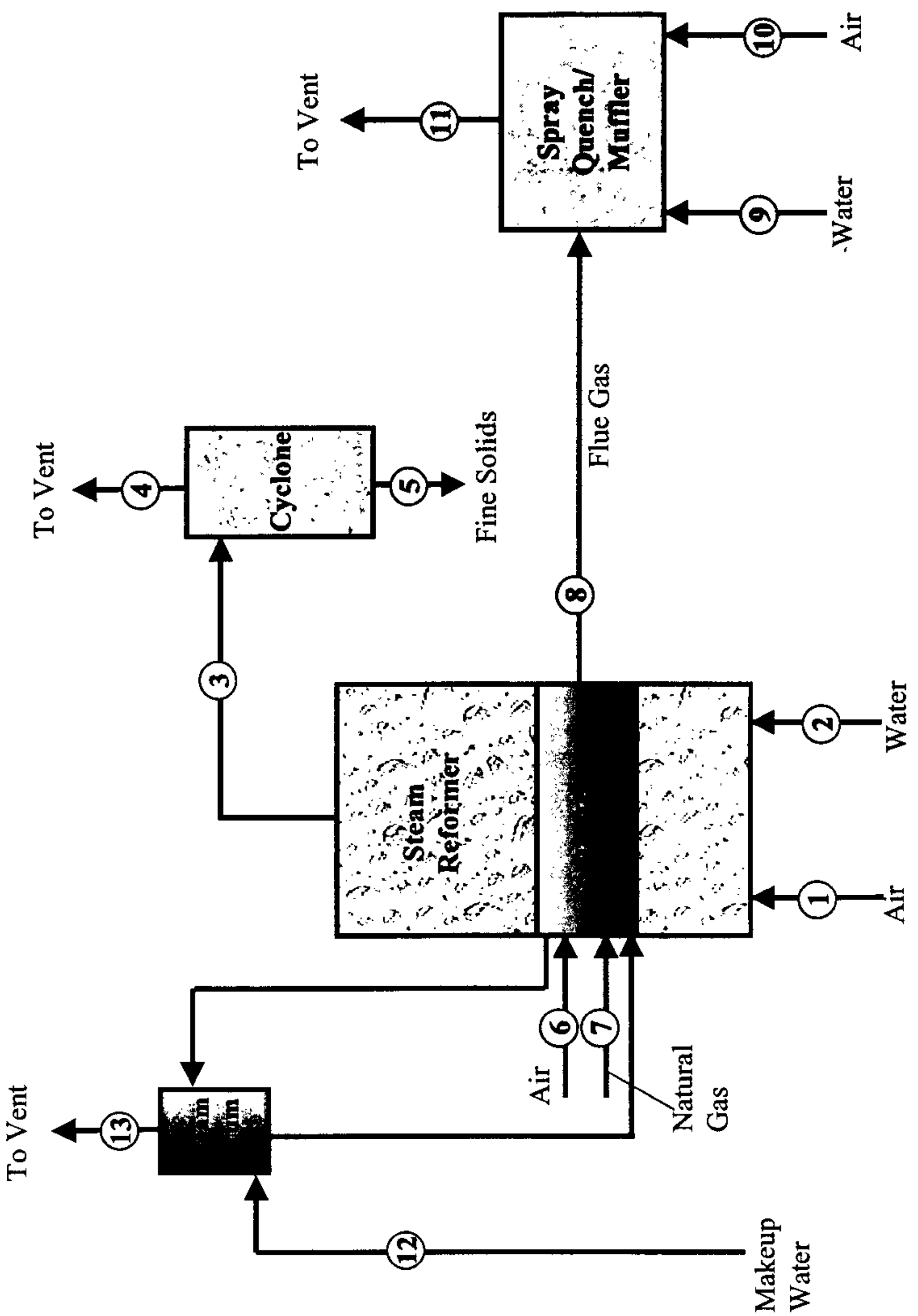



FIGURE 1-1: BLOCK FLOW DIAGRAM

exits (stream no. 4). The cyclone catch (stream no. 5) is collected in a drum for disposal.

The combustion air for the 253-tube pulse heater (stream no. 6) is delivered to the combustor by five combustion air fans. The combustor is fueled with natural gas (stream no. 7). A water spray (stream no. 9) cools the combustor flue gas (stream no. 8). This spray is generated by a dual fluid atomizer using air (stream no. 10).

The cooled flue and steam are vented (stream no. 11) through a muffler.

The cooling water for the water jacket of the pulse combustor tubesheets and the aerovalve plate cooling loop is circulated via a forced circulation pump, and the water makeup is provided by stream no. 12. Steam is vented from the steam drum (stream no. 13) to maintain a desired operating pressure of approximately 450 psig.

Table 1-1 presents a Mass and Energy Balance for the test facility.

The block flow diagram for the PDU study is presented in Figure 1-2.

In this PDU, the coal is fed into the steam reformer (stream no. 1) near the bottom of the reactor to provide sufficient residence time in the fluid-bed.

The feeder is comprised of a feed bin with a lock hopper below it, which discharges into a live-bottom-metering bin with three metering screws.

Three variable speed screws meter the coal to a constant speed auger that transfer the coal into the fluid bed.

Superheated steam (stream no. 2) from the superheater is used to fluidize the reformer (R). All instrument penetrations in the reformer are purged by nitrogen (stream no. 3).

Char (stream no. 4) is extracted from the fluid-bed steam reformer and constitutes the reductant for the DRI process.

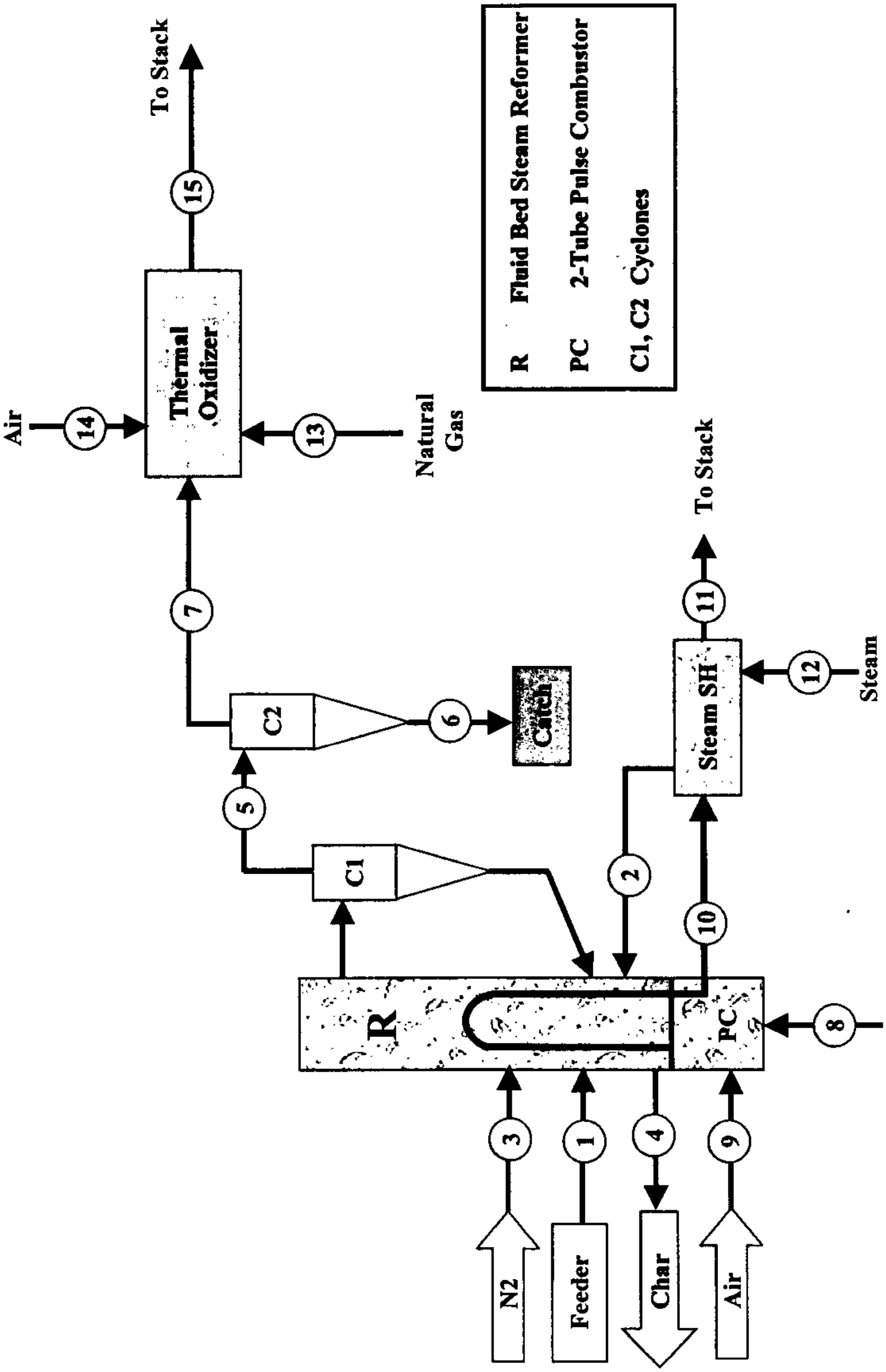



FIGURE 1-2: PDU PROCESS FLOW DIAGRAM

The product gas from the steam reformer passes through two stages of high efficiency cyclones (C1 and C2) and continues on to a Thermal Oxidizer (streams no. 5 and 7).

The first cyclone (C1) catch is returned to the fluid bed via a dip leg. The second cyclone fines catch (stream no. 6) is collected in a catch pot.

Natural gas (stream no. 8) is employed to fire a twin-resonance tube pulse combustor (PC). The combustion air (stream no. 9) is provided through an air plenum to the single aerodynamic valve of the pulse combustor.

The flue gas from the pulse combustor (stream no. 10) passes through the steam superheater which provides superheated steam (stream no. 12) for fluidization of the bed. The flue is sent to the stack (stream no. 11).

The thermal oxidizer employs a duct burner concept with natural gas (stream no. 13) and air (stream no. 14).

### 1.2.7 Project Location

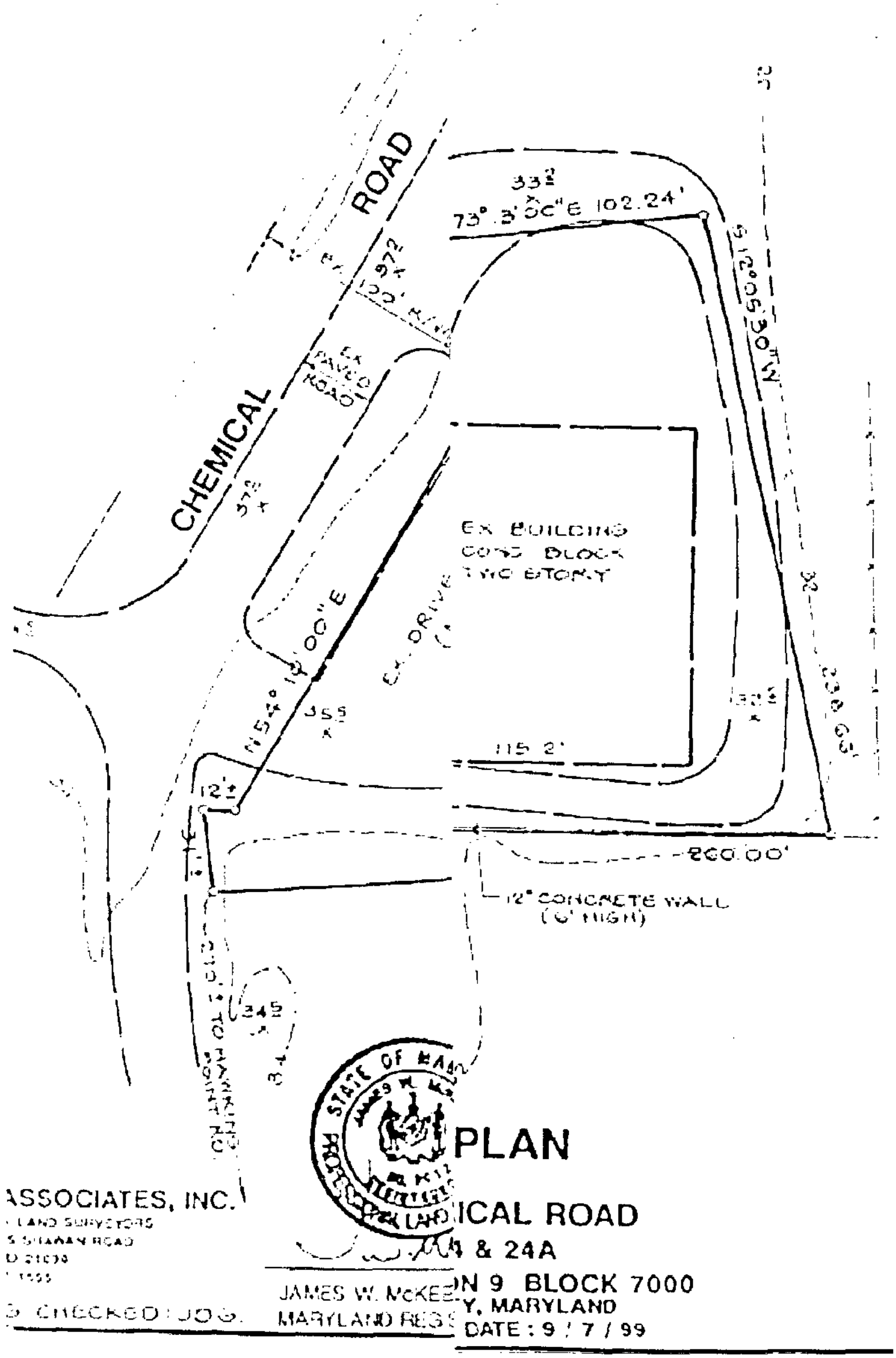
The project is located at ThermoChem's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor area within the Company premises and the PDU is located indoors in the Company Development and Manufacturing plant (see Figure 1-3).

### 1.2.8 Status as of the Date of the Report

As of the date of the report, the Pulse Combustor Design Qualification Test Facility has been constructed and commissioned. Testing has been conducted.

### 1.2.9 Summary of Test Program

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields


CHEMICAL ROAD
EX BUILDING
CONC BLOCK
TWO STORY
73° 3' 00"E 102.24'
N54° 1 00"E
115.2'
200.00'
12" CONCRETE WALL
(6' HIGH)
PLAN
ASSOCIATES, INC.
ICAL ROAD
& 24A
N 9 BLOCK 7000
Y, MARYLAND
DATE : 9 / 7 / 99
JAMES W. McKEE
MARYLAND REG

and composition, char yields and composition and endothermic heat requirements were determined in the PDU.

#### 1.2.9.1 Combustor Qualification Test Facility Description

Performance of a full-scale multiple resonance tube pulse combustor will be determined in the test facility constructed as part of this project. The facility consists of a fluid-bed heated by a full-scale pulse heater module. This test facility includes the following components:

- Fluid bed vessel with cyclone,
- 253-tube pulse heater module with inlet air plenum/muffler, exhaust plenum, water quench section and an exhaust muffler,
- Forced Draft fan to supply combustion air and air purge,
- Water/Steam loop with circulation pumps and a steam drum for cooling the pulse combustor tubesheet and aerovalve plate,
- Water injection system to provide a heat load in the fluid bed, and
- Instrumentation and controls.

Pictures of the 253-tube pulse heater test facility are shown in Figures 1-4 through 1-7.

Figure 1-4 provides a picture of the test facility while under construction. The view is from the exhaust side of the pulse combustor. This picture was taken after the insertion of the pulse combustor. The decoupler (flue gas plenum) of the full-scale pulse heater can be seen inside the lower nozzle on the vessel.

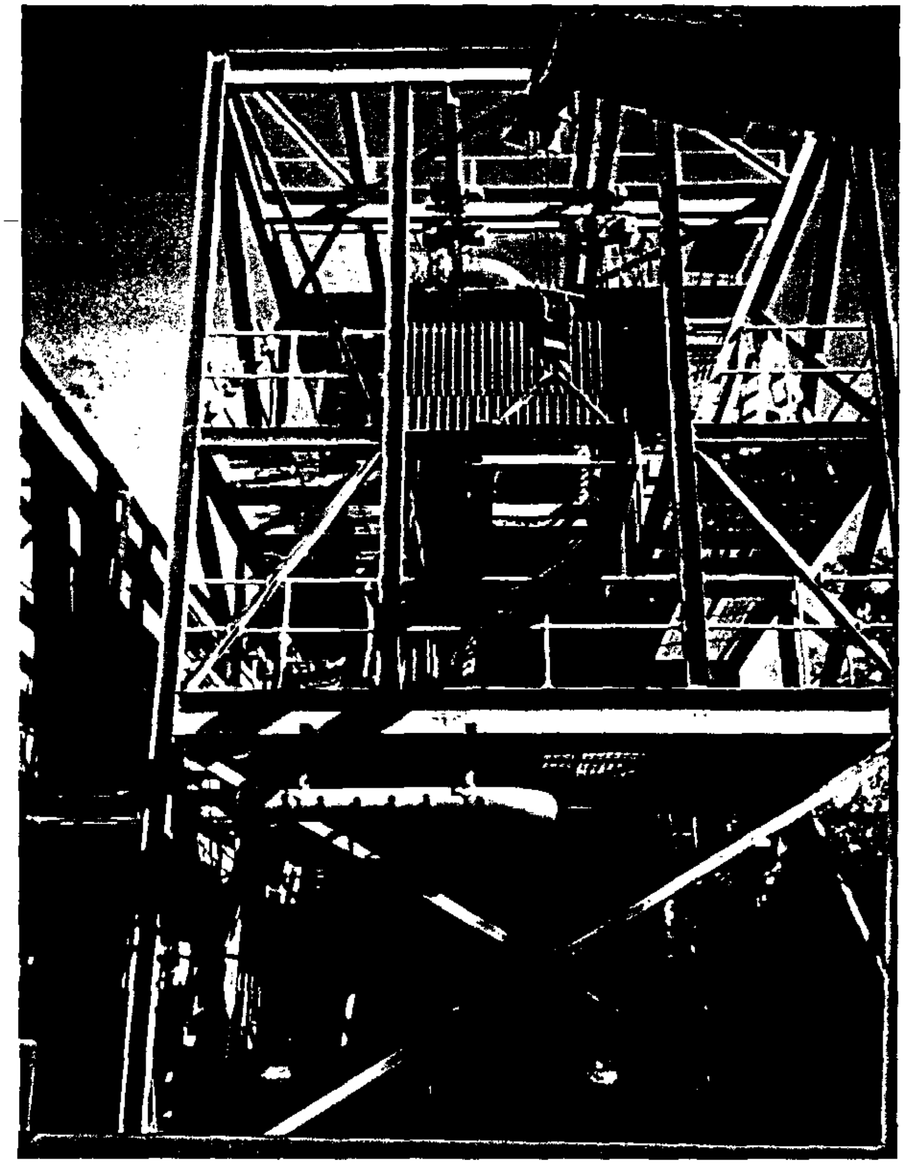


**FIGURE 1-4: FULL-SCALE PULSE COMBUSTOR TEST FACILITY UNDER CONSTRUCTION**

Figure 1-5 depicts the reactor vessel from the second level on the structure with the pulse combustor already inserted in the lower nozzle on the vessel. The view is from the combustion chamber side. The 253-holes in the refractory that could be seen make up the passage of the flue gas to the resonance tubes.

Figures 1-6 and 1-7 provide pictures of the 253-tubes pulse combustor as it is being installed in the lower nozzle on the vessel.

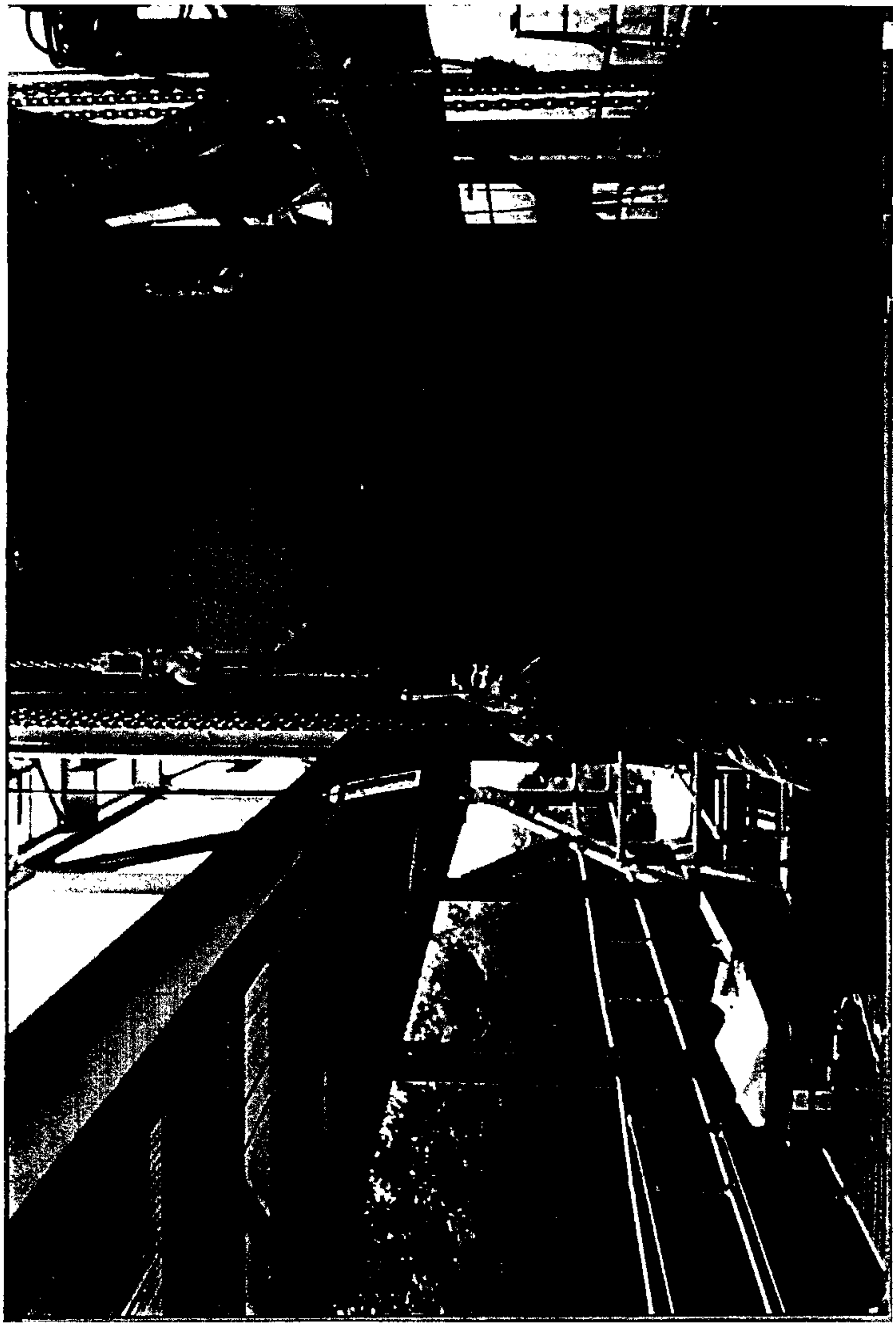


**FIGURE 1-5: 253-TUBE PULSE HEATER AFTER INSTALLATION IN THE VESSEL**

FIGURE 1-6: 253-TUBE PULSE HEATER BEING RAISED FOR INSTALLATION IN THE REFORMER VESSEL

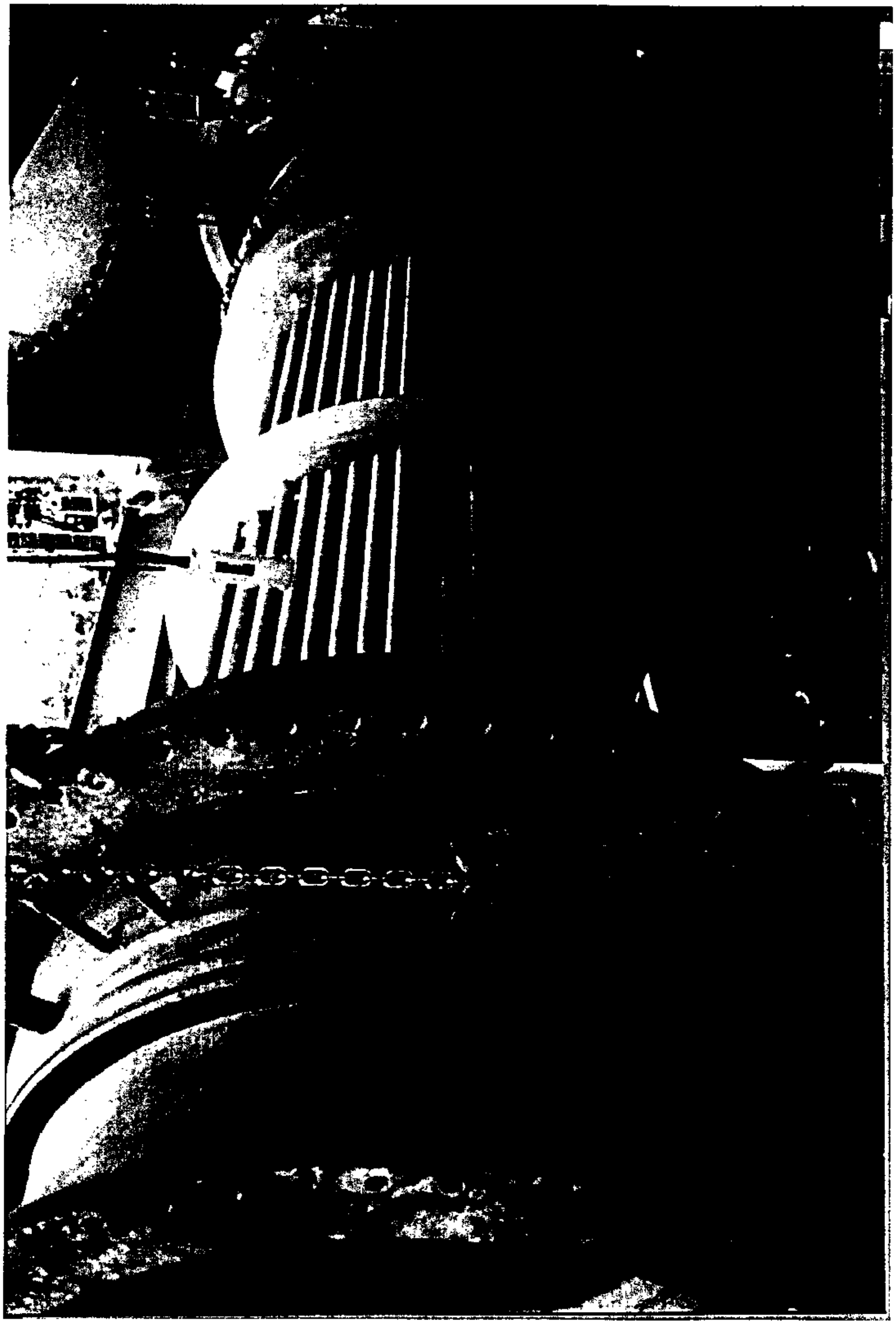


FIGURE 1-7: 253-TUBE PULSE HEATER READY FOR INSERTION

### 1.2.9.2 The PDU Test Facility Description

The PDU facility has a nominal feedstock capacity of 30 to 50 pounds per hour. Coal will be fed to the reformer reactor by a metering and injection screw system. Fluid bed temperatures are maintained at the desired levels by regulating the pulse combustor firing rate. At these temperatures, the feedstock undergoes high rates of heating, pyrolysis and steam reformation. In the absence of free oxygen, the steam reacts endothermically with the feedstock to produce a medium-Btu syngas rich in hydrogen.

The bed temperature is the variable that is controlled to maximize char production. As the bed temperature is lowered, the carbon/steam reaction rate slows and more char is produced. On the other hand, a reasonably high temperature is needed to reduce the sulfur content of the char and to produce lighter condensable hydrocarbons.

A description of the PDU components and subsystems is provided below. The PDU consists of the following subsystems:

- The steam reformer reactor and two-stage cyclone subsystem,
- Coal metering and injection subsystem,
- Steam boiler and feedwater reverse osmosis (RO) unit,
- Two stages of steam superheater,
- Gas chromatograph (GC) dry gas sampling and measurement,
- Instrumentation and controls.

An overall view of the steam reformer, the two stage cyclone, the second stage cyclone catch pot and the coal metering and injection subsystem is provided in Figure 1-8.

The bed area of the PDU reformer is an 8-inch diameter stainless steel vessel. Fluid bed height is approximately 6 feet. The pulse combustor resonance tubes are installed vertically through the bottom of the reformer vessel in a "U" shape. The resonance tubes are made of 1-½ inch pipe approximately 10 feet in length, identical to those used in the full-scale combustor. Since the resonance tubes are installed in a "U" shape, they occupy only five feet of the bed height.

**FIGURE 1-8: PDU TEST FACILITY**

The reformer operates slightly above atmospheric pressure. The startup fluid bed material consists of silica sand and is fluidized with low pressure (15 psig or 1 bar) superheated nitrogen. The reformer operates in the "bubbling" regime with a low superficial velocity of 0.5 to 1.0 foot per second. The low velocity ensures sufficient gas residence time. The two-tube pulsed heater supplies indirect heat for the steam reforming reactions.

A close-up view of the metering and feed system is provided in Figure 1-9. Coal is loaded into the bin at the top. A lockhopper is required because of the pressure differential between the fluid bed reactor and the metering bin. The feed rate control box is also shown in Figure 1-9. The lockhopper utilizes a Dezurik brand knife gate valve and a hemispherical valve to provide a seal between the feed hopper and the

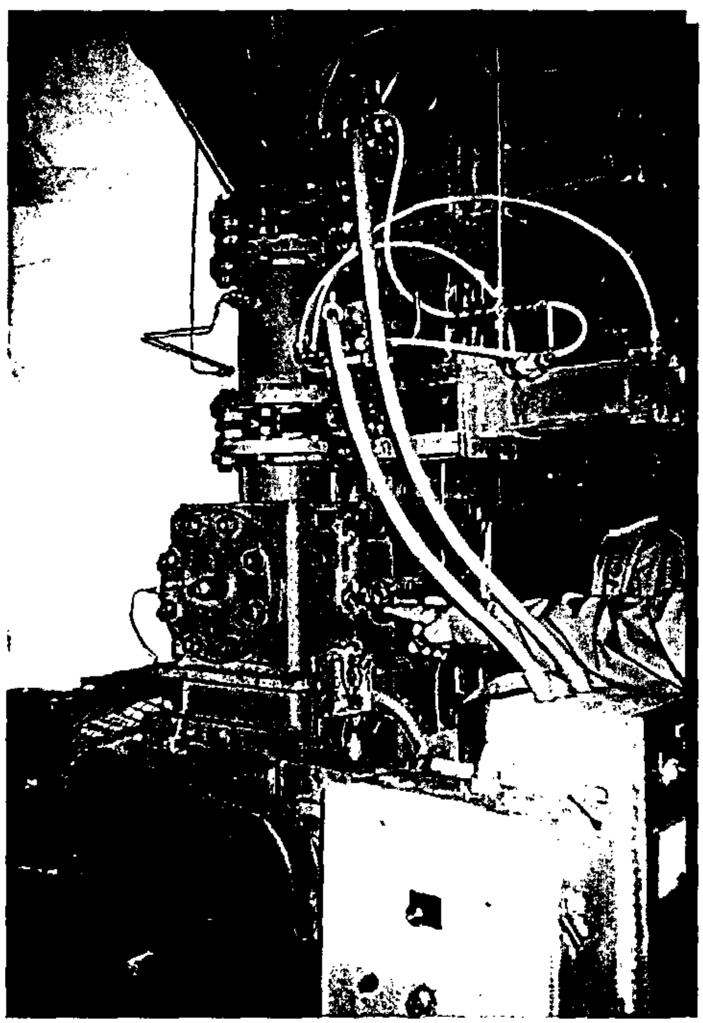


**FIGURE 1-9: COAL METERING AND INJECTION**

metering cavity. Three variable speed, parallel-drive metering screws provide volumetric flow control of the feedstock to the injection screw. The injection screw is operated at a constant speed and transfers the feed to the bottom section of the reformer vessel. The feed injection point is located near the bottom to increase product gas residence time in the bed.

As shown in Figure 1-10, the two-tube pulse combustor has one aerovalve that is supplied with combustion air from the air plenum.

To achieve sufficient oscillations at part load, the natural gas has provisions for air dilution.

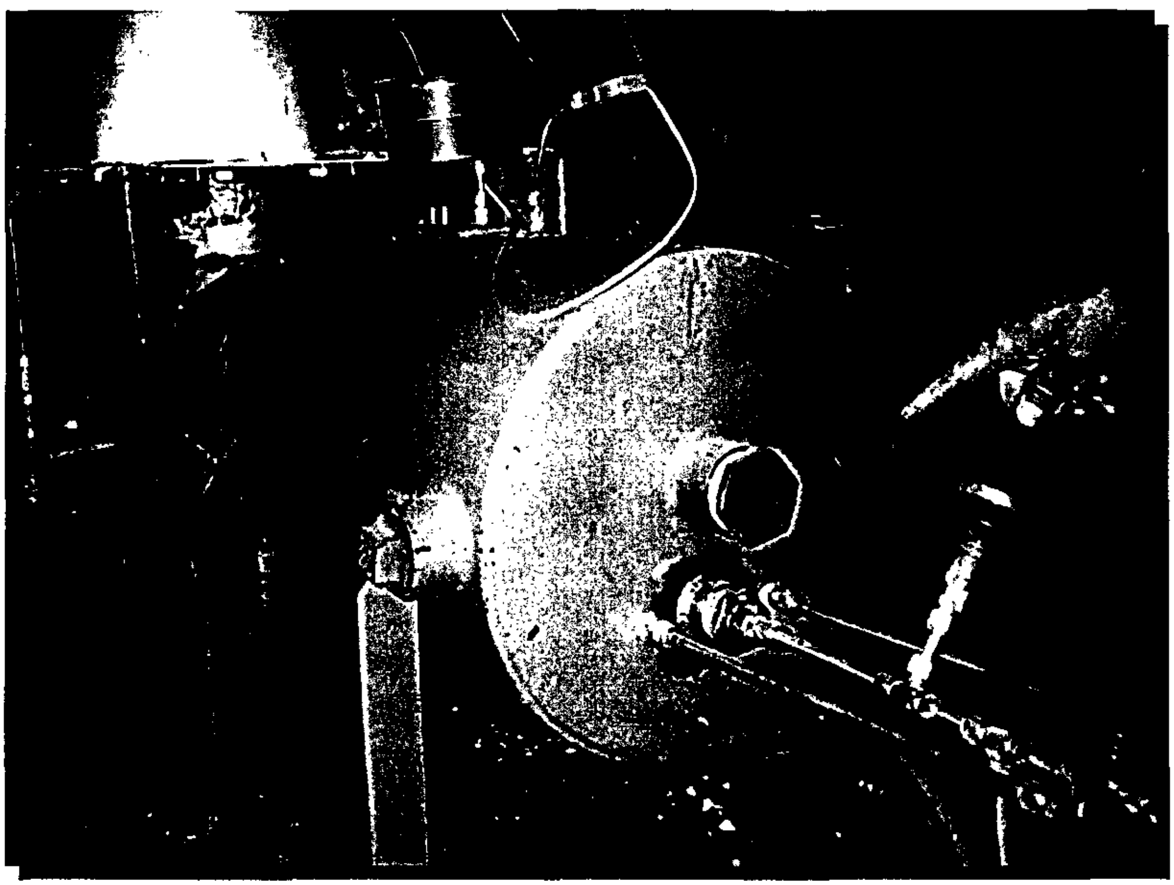


**FIGURE 1-10: PULSE COMBUSTOR COMBUSTION AIR PLENUM**

A close up view of the second stage cyclone catch pot is provided in Figure 1-11.

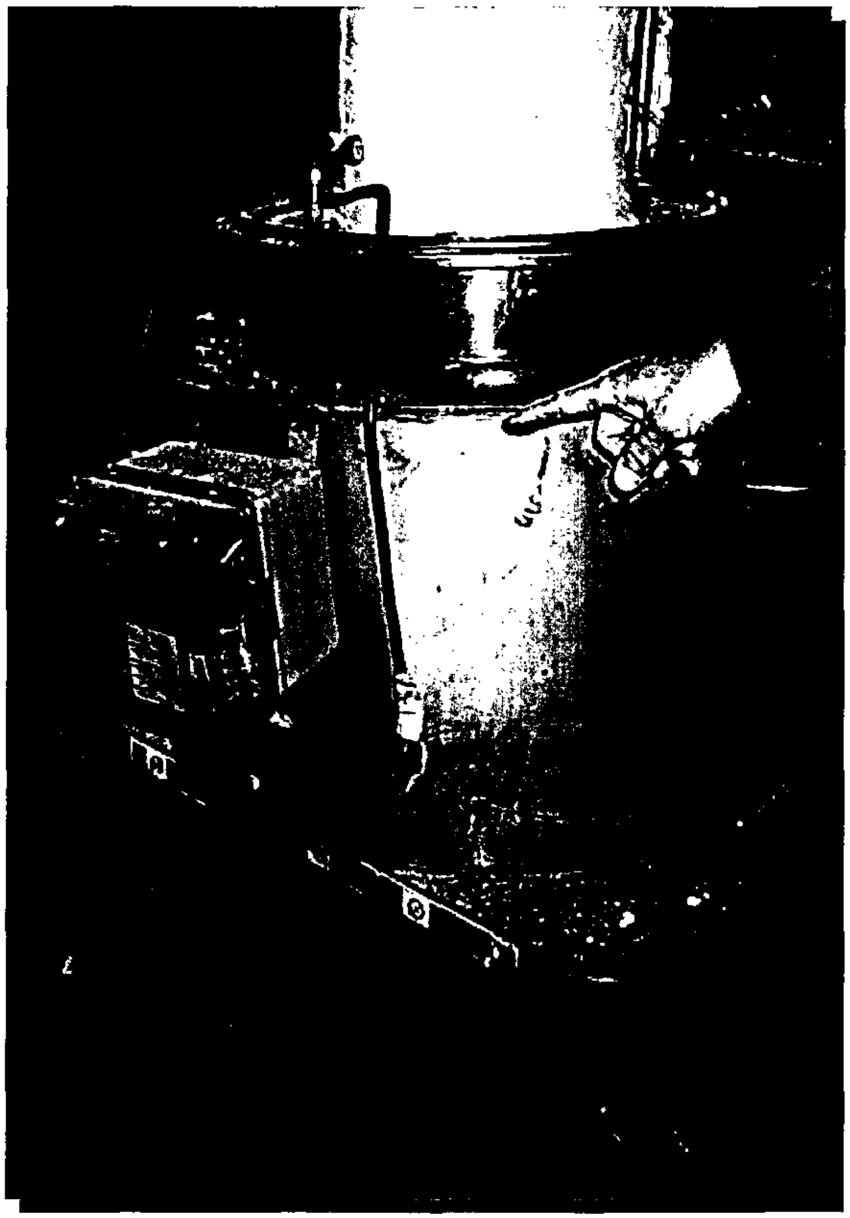


**FIGURE 1-11: SECOND CYCLONE CATCH POT**

A thermostatically controlled heating shell is provided to avoid steam condensation and refluxing near the end of the cyclone dip leg. A valve allows isolation of the pot for removal. A hydraulic table arrangement is used for moving the pot when disconnected from the dip leg allowing the catch to be sampled and weighed.

Figure 1-12 shows the boiler, which generates the steam used by the steam reformer, and the RO unit and storage tank for feedwater treatment.

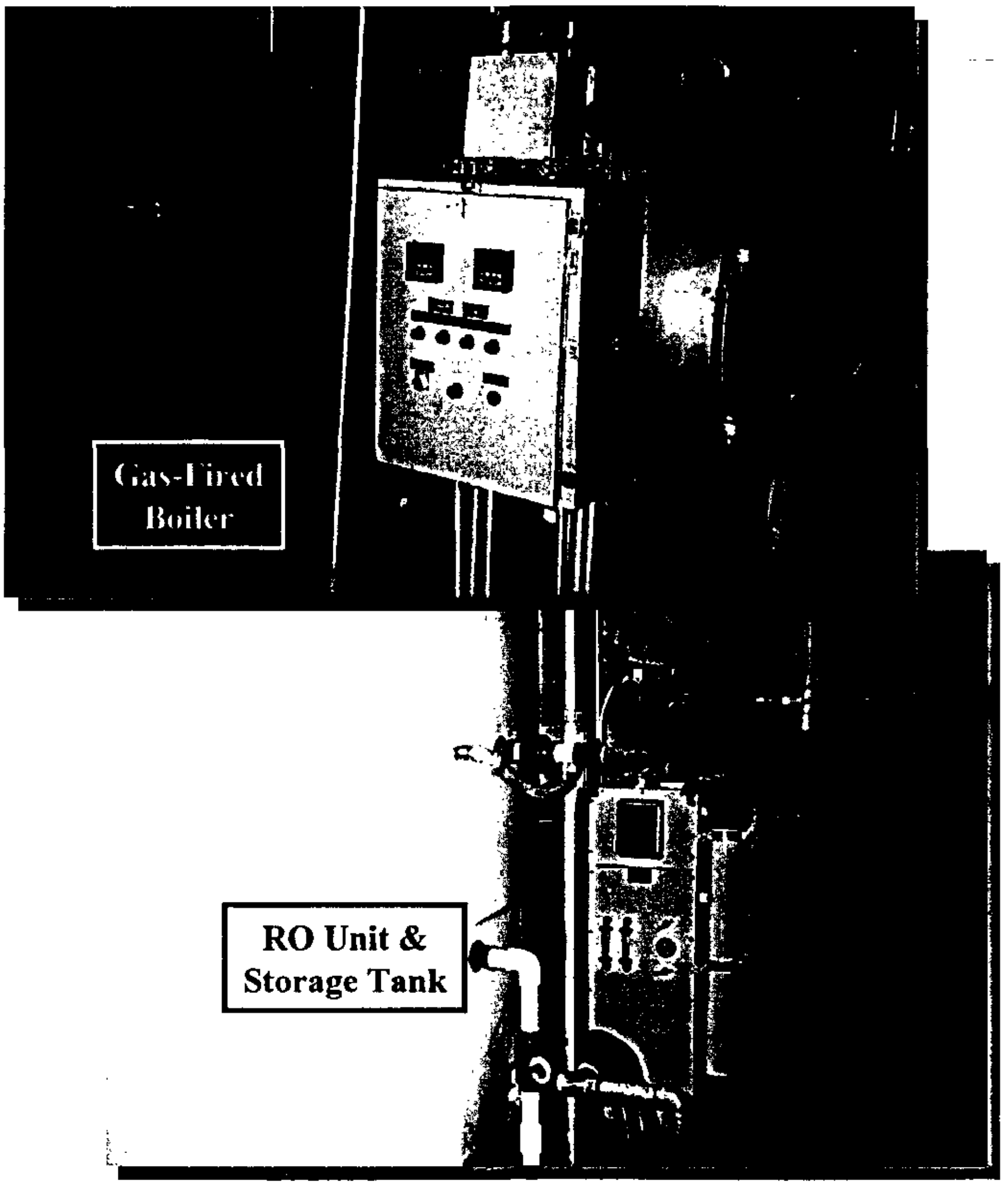



**FIGURE 1-12: STEAM BOILER AND FEEDWATER RO UNIT**

The natural gas fired boiler provides the supply steam at a nominal 100 psig (6.9 bar) pressure for operation of the PDU plant.

The superheaters employed are depicted in Figure 1-13. The first stage is a Watlow electrical heater which preheats the saturated steam from the boiler. The second stage is a coiled tube heat exchanger inserted in the PDU pulse combustor exhaust where it receives final superheat before being piped into the fluid bed.

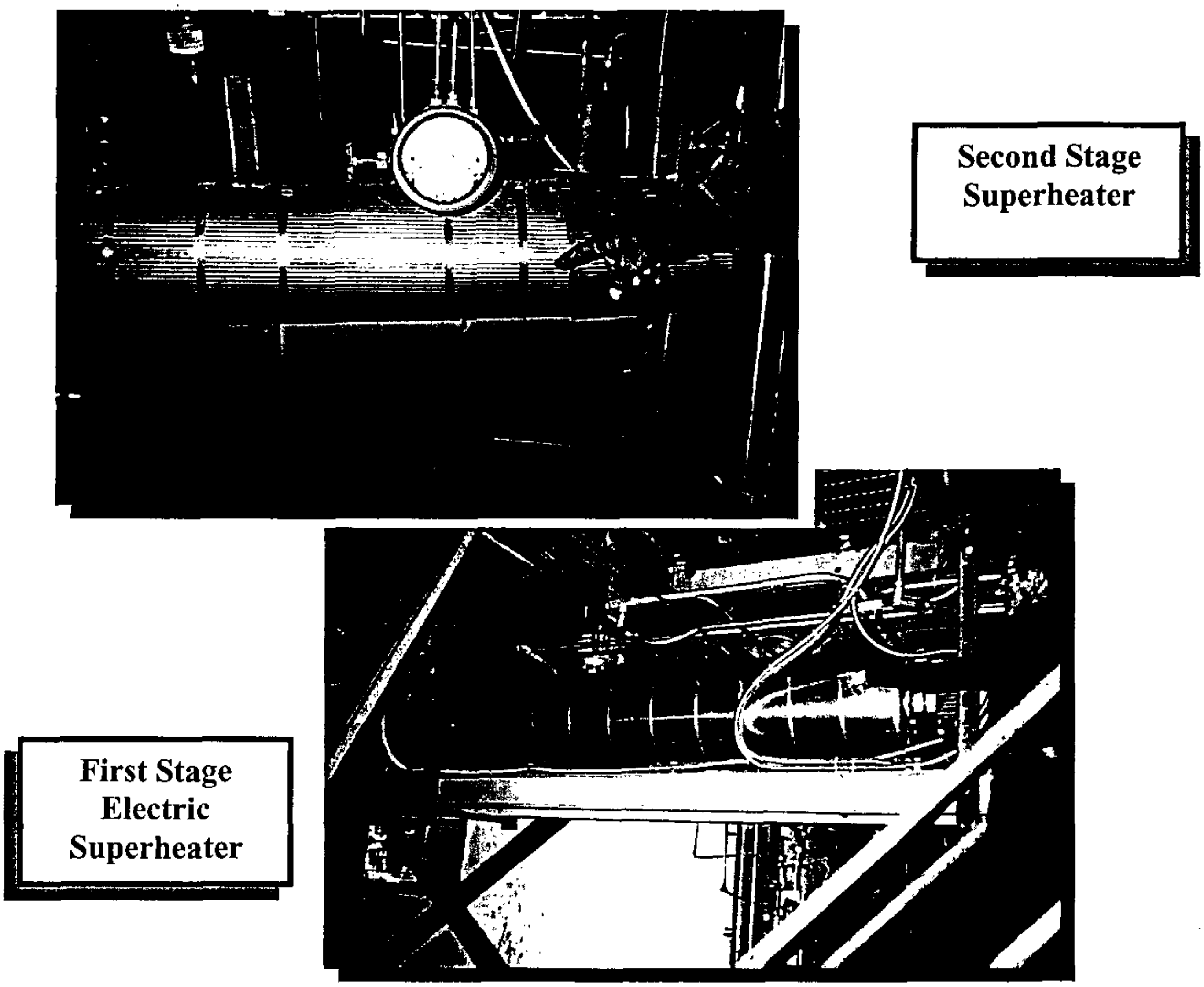



**FIGURE 1-13: SUPERHEATERS**

Typically, the steam temperature in the steam plenum is maintained at a temperature in the range of 950°F to 1,050°F.

The GC uses a small slipstream of the product gas flow for analysis. The sample product gas flow is first passed through a gas cleanup system, shown at the top of Figure 1-14.

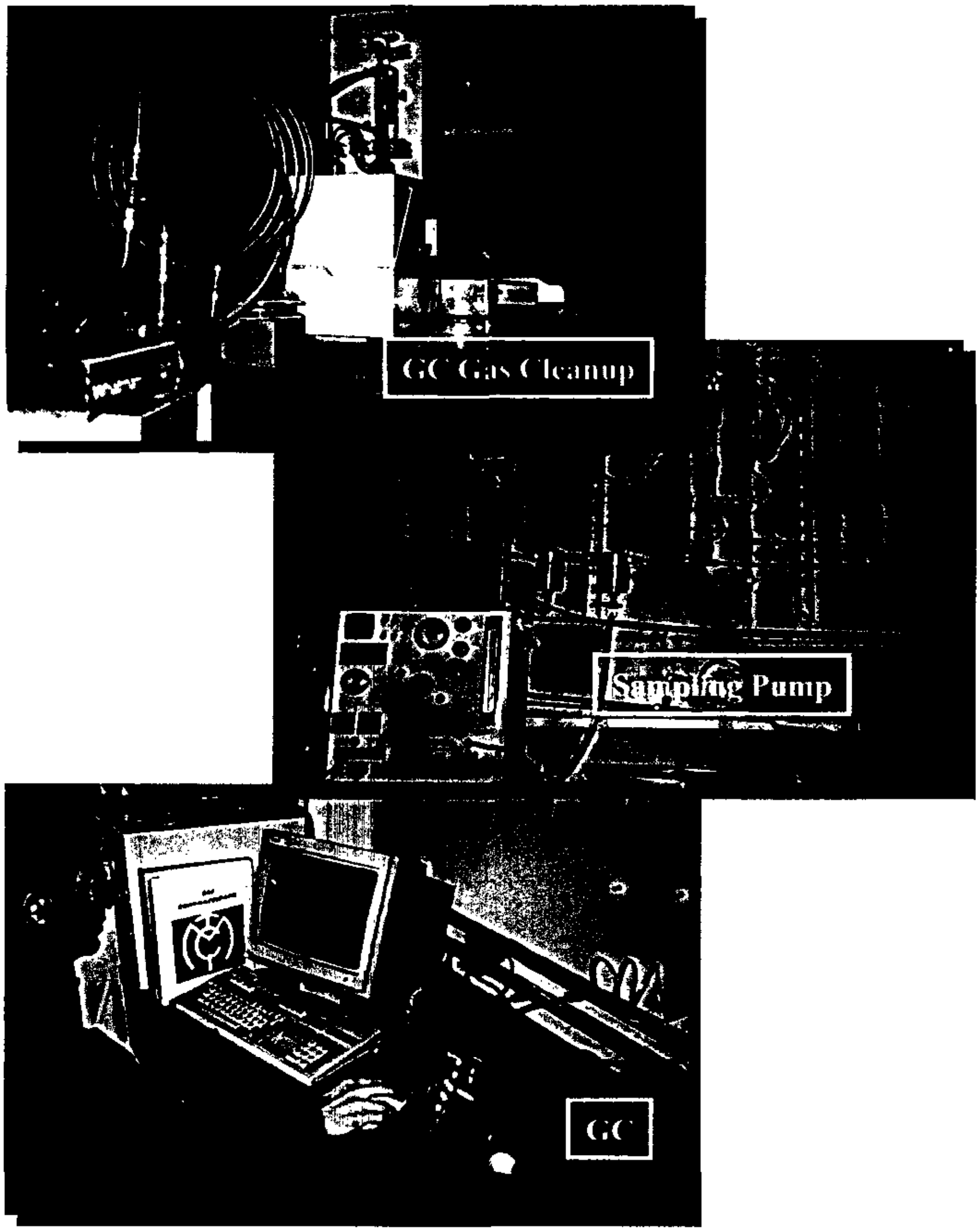



**FIGURE 1-14: GAS CHROMATOGRAPH**

The gas sample is then passed through the dry gas metering pump (middle of Figure 1-14).

Then the dry gas sample is passed through the GC for analysis (shown in the bottom picture of Figure 1-14). The GC operation is computer controlled with the GC data archived on the computer's hard disk.

Local analog controls (Figure 1-15) are utilized for startup, safe operation, process monitoring and control as well as for orderly startup and shutdown.

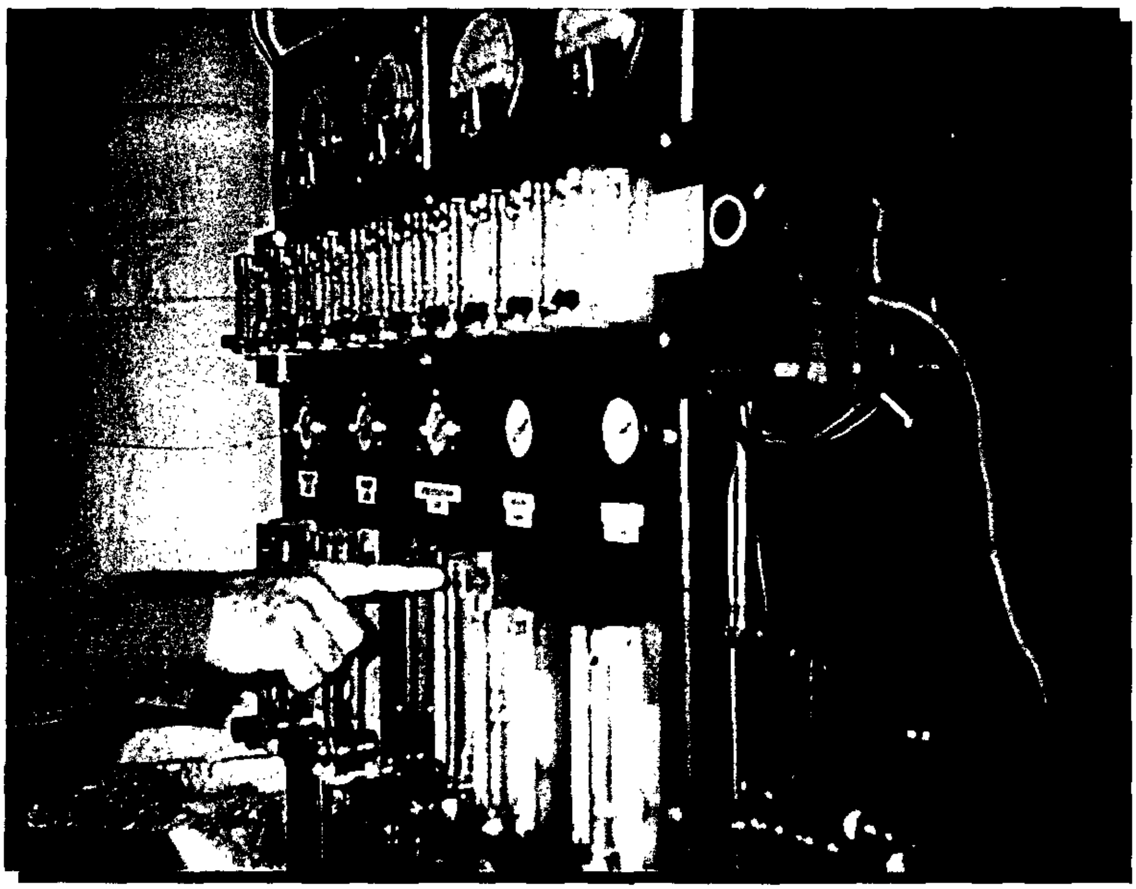


**FIGURE 1-15: STEAM REFORMER CONTROLS**

#### 1.2.9.3 Summary of Test Program

The test program include will parametric tests and parameter optimization tests to characterize the process performance in the full-scale test facility and in the PDU. The variables planned to be examined are:

- Pulsed heater excess air ($O_2$) level,
- Pulsed heater-firing rate,

- Steam reformer-operating temperature
- Fuel/air premixing ratio,
- Fuel type – natural gas, and syn gas, and
- Superficial fluidization velocity of the fluidized bed.

Species that will be measured for the PDU are CO, $CO_2$, $NO_X$, $SO_2$, $O_2$ and total hydrocarbons. These will be measured for the flue gas in both tests and for the product gas in the PDU test. A continuous Emissions Monitoring System that comprises a gas conditioning subsystem and gas analyzers will be used for determining the flue gas composition.

#### 1.2.9.3.1 Combustor Qualification Test Description

Performance of a full-scale multiple resonance tube pulse combustor will be determined in the test facility constructed as part of this project. The pulse combustor's role in the reformer is to provide the process heat required. The combustor will be test fired on natural gas. The amount of heat that can be supplied by the pulse combustor will be determined at various operating conditions. Combustor firing rate and excess air levels are the variables to be examined with respect to the combustor. Of course, the amount of heat that can be transferred to the fluidized bed is also dependent upon the conditions within the bed (bedside heat transfer coefficient) and the tube-to-bed temperature difference. The tube temperatures and bed temperatures will be monitored and used in conjunction with energy balance data to determine the bedside heat transfer coefficient. Combustor efficiency and emissions will be determined at various firing rates (up to 25 million Btu/hr), excess air levels (20% to 60%), and fluidized bed operating temperatures (1,100°F to 1,400°F).

The fluidized bed test facility will be filled with sand and fluidized with air. Water will be injected into the bed to impose a heat load, thereby controlling the bed temperature independently of combustor firing rate. Gas flow and combustion airflow rates will be measured for each test. The pulse combustor flue gas will be analyzed to determine the concentration of oxygen, carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxides, and hydrocarbons. This data will be used to assess combustion efficiency at various firing rates and excess air levels and will provide the basis for the commercial configuration system using this general combustor design.

The fluidized bed temperature, fluidizing air flow, water flow for bed temperature control, pulse combustor exhaust temperature, resonance tube temperatures, combustion air temperature and combustor cooling circuit steam generation will be measured for each test. This data will permit projections of an energy balance and quantification of the amount of heat transferred to the bed and the tube-to-bed heat transfer coefficient.

#### 1.2.9.3.2 PDU Test Description

The production of char in the PDU for DRI is the basis for selecting the coal to be tested in the PDU. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant. In the char production application, the primary variable will be operating temperature. The goal is to identify the lowest temperature at which satisfactory sulfur and volatile matter content reduction is achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby increasing product yield. The lower operating temperature also provides a higher tube-to-bed temperature differential, which improves the amount of heat transfer into the reformer and increases throughput. Complete mass and energy balances will be performed for each steady state PDU test to verify mass closure and to determine the process heat requirement. The coal feed rate, fluidizing steam rate, and instrument purge (nitrogen) rates are measured for each test. A slipstream of product gas is collected in an EPA Method 5 impinger train and the steam and condensable hydrocarbons are collected for analysis. Fixed gas composition is determined by on-line gas chromatography. Product char will be collected and analyzed for comparison with the targets provided earlier (see Section 1.2.5). The fluid-bed temperature distribution will be monitored by thermocouples inserted in thermal wells so as to permit replacement of thermocouples during operation. The locations of the thermocouples were selected to span the fluid bed such that any maldistribution in fluidization and bed temperature uniformity can be detected. Since the fluid bed removes heat from the resonance tubes of the pulse combustor, uniform bed fluidization is important in maintaining uniform tube temperatures and efficient heat flux and heat transfer conditions from the resonance tubes to the bed. The bed height will be measured by two sets of pressure differential measurements. The pressure differential between two locations at a known height between the two pressure-monitoring taps in the bed will be employed to monitor the expanded bed density (pressure drop per unit bed height).

Samples of the product gas condensate will be submitted to an independent laboratory for analysis. On-line gas chromatography will be utilized to determine product gas composition, yield and heating value. Employing the PDU's semi-automated data acquisition system, all process variables will be data logged every thirty (30) minutes to develop trend information. The product gas composition (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, methane, acetylene, ethylene, ethane, propylene, and propane will be determined on line with the MTI M-200 gas chromatograph. Draeger tubes will be employed to monitor ammonia and hydrogen sulfide in the product gas. Utilizing an EPA Method 5 gas sampling train, product gas condensate samples will be collected, quantified and submitted to an independent laboratory for analysis. Laboratory determinations will include volatile organic compounds (VOC's), semi-volatile organic compounds (SVOC's), Chemical Oxygen Demand (COD), Biological Oxygen Demand (BOD), chloride, sulfur and nitrogen compounds.

### 1.2.10 Overall Project Schedule

Shakedown and qualification testing of the scaled-up combustor was conducted from October, 2000 through early June 2001. The coal testing in the PDU was conducted in April, 2001.

## 1.3 Objectives of the Project

The purpose of the revised project is the design qualification of a scaled-up 253-tube pulse heater as an essential step for the commercialization of this technology. The 61- or 72-tube heater bundles, as previously used, are too small for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units employing the technology will require 253-tube heater bundles.

### 1.3.1 Qualification Test Objectives

The principal objectives of this program are to perform design qualification testing of a 253-tube pulse heater and to demonstrate its ability to operate in the pulse combustion mode for commercial deployment. The specific objectives include verification and demonstration of:

- Full-scale pulse heater performance and operability; and
- Emissions ($NO_X$, THC, CO) determination;

### 1.3.2 PDU Test Objectives

The objectives of the PDU test will be to evaluate the operability and performance of the system. Specifically, the targets will be:

- Safe, stable and reliable operation,
- Material balance analysis,
- Energy balance analysis,
- Heat of reaction determination,
- Char production and composition determination,
- Product gas composition and yield,
- Bed solids characterization, and
- Cyclone catch solids characterization.

The process data generated from the test will be used for preliminary system design for the full-scale commercial plant.

## 1.4 Significance of the Project

The design qualification of the 253-tube heater bundle will enable ThermoChem to establish the design parameters of the scaled-up heater in order to meet the requirements of the overall system performance for commercial use. Process fluid mechanics, heat transfer, mass transfer and mixing must be preserved in the scale-up to achieve good system performance. For example, the combustion chamber aspect ratio (height-to-diameter) decreases with an increase in pulse heater module size due to acoustic and geometric considerations. This reduced aspect ratio could affect lateral mixing of the fuel and air, temperature uniformity in the resonance tubes, and proper mass flow distribution of the flue gas across the resonance tube-sheet. In addition, the scaled-up heater must be designed to achieve heat addition that is substantially in phase with pressure oscillations. Appropriate controls and instrumentation must also be used to demonstrate to ThermoChem's EPC partners and bonding/insurance companies the efficacy of the technology in full-scale commercial applications.

Qualifying the design of the 253-tube pulse combustor is an enabling measure for the commercial introduction of the MTCI technology in a wide spectrum of end use applications. The MTCI steam-reforming technology is unique with regards to the wide spectrum of feedstocks it can process.

In the area of coal applications, the MTCI steam reformer has the following end use application opportunities:

- Complete steam reforming of sub-bituminous coal and lignite at the mine mouth and producing power with combined cycle gas turbines and Fuel Cells. In fact, the MTCI technology is the most suitable technology today for the production of reformate gas from coal and waste (combined) in the world.

- Mild gasification of coal for production of char, tars and fuel gas for the U.S. steel industry. In the case of Northshore, the char is used for a DRI process. The tar would be sold to a company the makes asphalt and the exported gas would be used for taconite processing.

Several other promising coal applications are described in Section 7 of this report.

In addition, the MTCI steam reformer technology can process a wide spectrum of coal and wastes (RDF, chicken waste, sewage sludge, hog waste, biomass waste and essentially any liquid or solid material that contains carbon or hydrocarbons (i.e. tires, plastics, etc.).

The target is to use the underutilized sub-bituminous and lignite coals that also have highly reactive char and wastes to produce clean power and/or other products (ethanol, methanol, acetic acid, etc.).

This is very significant application and would be enabled by the qualification of the pulse combustor (the technology envelope) scale-up design qualification.

In other applications, the MTCI technology is the leading technology for processing biomass based feedstocks (black liquor, bark, pistachio nut shells [with 4% sulfur], toxic wastes from industrial sources, as well as low level mixed waste and low level wastes).

The MTCI technology is unique in the broad spectrum of its end use applications.

## 1.5 Management and DOE's Role

### 1.5.1 Department of Energy

DOE provided 50% of the funds for this project and monitored project progress and results.

### 1.5.2 Project Management and Execution

Thermochem Project Manager is responsible for project execution and cost/schedule monitoring and control. The Project Manager was also responsible for supervising the project team including consultants and subcontractors.

### 1.5.3 Project Organization Chart

As depicted by the project organization chart, the ThermoChem project manager, Mr. William Steedman, is the interface with the DOE project manager.

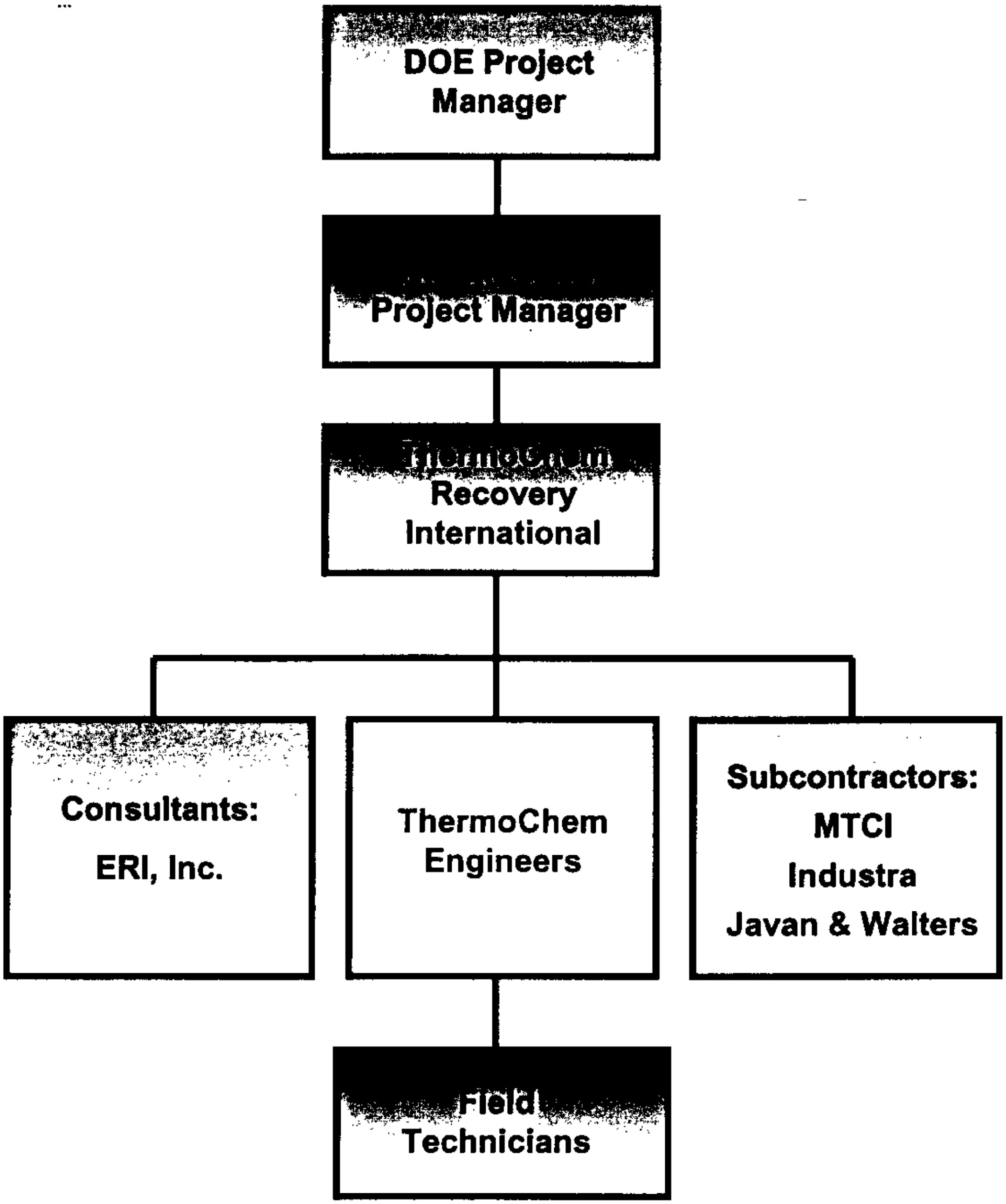



**FIGURE 1-16: ORGANIZATION CHART**

ThermoChem Recovery International is the private sector cost sharing entity on this project for the Pulse Combustor Design qualification test and the process investigations conducted using the PDU.

The technical project team is comprised of ThermoChem engineers, MTCI engineers, engineers from Industra and Javan & Walters.

In addition, MTCI supplied fabrication and site erection personnel as part of the team.

MTCI also augmented the ThermoChem Engineers with test operation personnel.

Temporary Field Technicians were also employed on as needed basis to support electrical, welding and test operation activities.

## 2.0 TECHNOLOGY DESCRIPTION

### 2.1 Brief Description of the Technology Being Used

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor.

In the ThermoChem steam-reforming system, the multiple resonance tube pulse combustor is employed in which the resonance tubes serve as the heat exchanger to deliver heat indirectly to the fluid-bed reactor. At any significant firing rate, a single resonance tube will not have sufficient surface area to transfer all the heat necessary to the fluid bed. Therefore, multiple parallel resonance tubes must be employed. In scaling up the multiple resonance tube pulse combustors, the number of the parallel resonance tubes is increased and the ratio of the combustion chamber depth to its diameter is reduced. It is essential that the oscillatory component of the flow velocity in all the resonance tubes be in phase to achieve strong pulsations and, thus, enhanced heat transfer and heat release rates.

The larger the number of tubes, the more critical is the tuning of these self-induced, combustion-driven oscillations. Therefore, a number of independent aerodynamics valves are employed to introduce the combustion air to various segments of the combustion chamber. When tuning a multiple resonance tube pulse combustion system, it is necessary to achieve high pulsation amplitudes in order to ensure a more even distribution of the hot flue gases between the resonance tubes. Such distribution is critical given the high-temperature range required for the heat duty to which the resonance tubes are subjected. Additional information relevant to the description of the technology is provided in subsections 1.2.6, 1.2.9.1 and 1.2.9.2. A discussion of some of the applications of the MTCI technology is provided in subsection 1.4 (Significance of the Project) of this report.

### 2.1.1 Proprietary Information

ThermoChem considers the specific costs of the pulse heater and reformer vessel and detailed temperature distributions, including temperature profile of the resonance tubes to be proprietary. Form fit and function data or aggregated costs and performance information will be furnished in lieu of detailed proprietary information.

## 2.2 Overall Block Flow Diagram

The project block flow diagram has been presented earlier in this report (please see Section 1.2.6). This project deals with the qualification of a scaled-up combustor. Therefore, the overall block flow diagram is identical to the project block flow diagram. The material and energy balance flows into and out of each process area have also been previously tabulated (please see Section 1.2.6).

## 3.0 PROCESS DESIGN CRITERIA

The relevant process design parameters and design criteria are provided in Tables 3-1, 3-2 and 3-3. Table 3-1 presents criteria for the 253-tube Pulse Combustor, Table 3-2 is for the test facility for the 253-tube combustor, and Table 3-3 is for the PDU.

The commercial configuration is the 253-tube that was scaled-up from the New Bern, North Carolina 72-tube combustors which also have 1-½" inch, schedule 40 stainless steel pipe for the resonance tubes. For coal applications the material of choice is SS 310.

Since the 253-tube combustor has the same resonance tube length, the design frequency range as shown in Table 3-1 is from 55 Hz to 65 Hz. This would allow the unit to operate as a quarter wave Helmholtz resonator in the first mode with maximum heat-transfer-profile benefits. The design maximum firing rate is 30 MMBtu/h.

The design operating stoicchiometry range in Table 3-1 is from 20% to 60% excess air. In essentially all the near term commercial opportunities, 60% excess air is optimum from a system design point of view. Essentially all such applications contemplate a re-burn of the pulse-combustor flue gas in a boiler.

Because of this near term need for initial market entry of the technology, the design targets are for low $NO_X$ with higher CO. In combustion system, a trade off between $NO_X$ and CO/THC emissions exists. Nevertheless, the target design levels are provided in Table 3-1 and are believed to be achievable with FGR.

Notwithstanding that the freeboard operating pressure is in the 6 to 8 psig, the fluid-bed shell is to be designed as an ASME code pressure vessel with a design pressure of 15 psig. This is to provide a safety margin for the fluid-bed vessel design.

The bed material shall be silica sand with a mean particle size distribution of 250 μ to 350 μ. This would be a suitable bed mean particle size to enable good fluidization and heat transfer coefficient between the tubes and the bed at a fluidization velocity of 1.0 to

1.4 ft/second. This is typical for what would be employed in the full-scale commercial systems. The low fluidization velocity essentially minimizes the erosion rate (function of the cube of the fluidization velocity) of the tubes and the mean particle size provides for high heat transfer.

### TABLE 3-1: PROCESS DESIGN CRITERIA

### PULSE COMBUSTOR

| TEST AREA | DESIGN PARAMETER | VALUE | REMARKS |
|---|---|---|---|
| Pulse Combustor | Number of resonance tubes | 253 Resonance tubes<br>1.5 Inch Pipe Schedule 40 SS 310 | Commercial Size Scale-up |
| | Frequency | 55 to 65 Hz | Function of resonance tube length, firing rate, air-to-fuel ratio and bed temperature |
| | Firing Rate | Maximum 30 MMBtu/h. Operating 4 MMBtu/h to 25 MMBtu/h. | 5 MMBtu/h (20%) Margin |
| | Stiochiometery | 20% to 60% excess air | Will depend upon process integration requirements |
| | $NO_X$ Emissions | Below 30 ppmv | |
| | CO Emissions | Below 300 ppmv | Will be reduced materially in the re-burn |
| | THC Emissions | Below 20 ppmv | |
| | Flue Gas Plenum (Decoupler) insulation | Ceramic Fiber insulation (Min. 2") to reduce the plenum metal temperature. | Improvement over the New Bern design |

The design fluidization velocity is in the range of 1.0 to 2.0 feet per second. The fluidization air supply shall be capable of fluidizing the bed during startup (cold) at a fluidization velocity of 1.4 foot per second.

A high efficiency cyclone arrangement shall be used for solids separation to capture solids that is entrained with the fluid bed exit flow.

The nominal pressure for the steam drum of the cooling loop shall be 450 psig. The stamped pressure rating for the cooling water jacket of the combustion chamber and the aerovalve plate water-cooling loop is 500 psig. This provides a margin of safety for the cooling loop of 50 psig.

The PDU (Table 3-2) will be configured such that the capacity of the unit would be in the range of 30 to 50 lb/h for the coal provided by the Northshore Mining Company. This feed rate range would be processed at a bed temperature of 1,000°F to 1,200°F, which is the design criteria for mild gasification.

The bed solids mean particle size design ranges 275 μ ± 25 μ. This particle size is optimum for the operation of the PDU that allows low fluidization velocity in the range of 0.5 to 1.4 feet per second (low erosion rates for the tubes) with good heat transfer between the tubes and the fluid bed.

The PDU has two stages of high efficiency cyclones will be employed to achieve more accurate mass balance closure regarding bed solids and char yield.

A hot box filter and a condensation train of glass impingers in an ice bath (EPA Method 5) will be employed for the GC sampling train slip stream for measurement of dry gas analysis and condensable hydrocarbon yield.

## TABLE 3-2: TEST FACILITY PROCESS DESIGN CRITERIA

| TEST AREA | DESIGN PARAMETER | VALUE | REMARKS |
|---|---|---|---|
| Test Facility | Reactor Vessel Design Basis | 15-psig freeboard pressure ASME Pressure Vessel Code. Static, Wind and Seismic Loads | The Vessel does not operate at pressures that would require it to be designed as a pressure vessel. The freeboard pressure during operation is in the range of 6 to 8 psig. |
| | Bed Material | Silica Sand. Mean Particle size 250 μ to 350 μ | μ means Microns. This low range is chosen to obtain good fluidization and heat transfer from tubes to bed at low fluidization Velocity |
| | Fluidization Velocity | 1 to 2 feet per second | Low for low erosion rates of the pulse heater tubes |
| | Source of fluidization medium | Compressed Air 100 to 140 psig and 5500 SCFM air | Also Water injection will be employed for imparting heat load on the fluid-bed and the heater |
| | Solids Separation | High Efficiency Cyclone | |
| | Steam Drum Pressure | Nominal 450 psig | Cooling loop for the pulse combustor's tube sheet water Jacket and aerovalve plate |

## TABLE 3-3: PDU PROCESS DESIGN CRITERIA

| TEST AREA | DESIGN PARAMETER | VALUE | REMARKS |
|---|---|---|---|
| PDU | Unit Throughput | 40 to 50 lbs per h | Function of bed temperature, moisture in the feed and the heat of reaction of the particular coal fed |
| | Bed Solids | Silica sand. Mean Particle size 275 μ ± 25 μ | Allows low fluidization velocity (lower erosion rates) with sufficient tube to bed heat transfer coefficient |
| | Fluidization Velocity | 0.5 to 1.4 foot per second | Erosion is proportional, on the first order, to the cube of the fluidization velocity. Fluid bed coal combustors typically operate between 6 and 9 ft/second fluidization velocity. |
| | Gas Cleanup Train | High efficiency particulate removal train and Thermal Oxidation | Two Stages of High efficiency cyclones before a thermal oxidizer. |
| | Gas Sampling Train for Analysis in GC | EPA Method 5 Train with hot box filter and condensation stages of glass impingers in an ice bath | The GC can only measure properly dry gas with essentially no condensable hydrocarbon vapor partial pressure. |
| | Steam superheat | 500° to 800° F | Function of bed temperature and fluidization medium mass flow rate |

# 4.0 DETAILED PROCESS DESIGN

## 4.1 Plot Plan and Plant Layout Drawing

The Plot Plan (Site Plan) is shown in Figure 4-1. The Pulse Combustor Test Facility occupies the small shaded area on the south side of MTCI's Laboratory and Fabrication Plant Facility. The layout of the Equipment is shown in Figure 4-2. The test vessel occupies the large central area. The pulse combustor is installed inside the vessel from the eastside. The pulse combustor exhaust is ducted to the westside of the test vessel and is then vented through a muffler.

The flash drum that is part of the pulse combustor cooling circuit is installed near the northeast corner of the fluid-bed vessel roof. The boiler feedwater pump and recirculation pump are both located on the eastside of the structure.

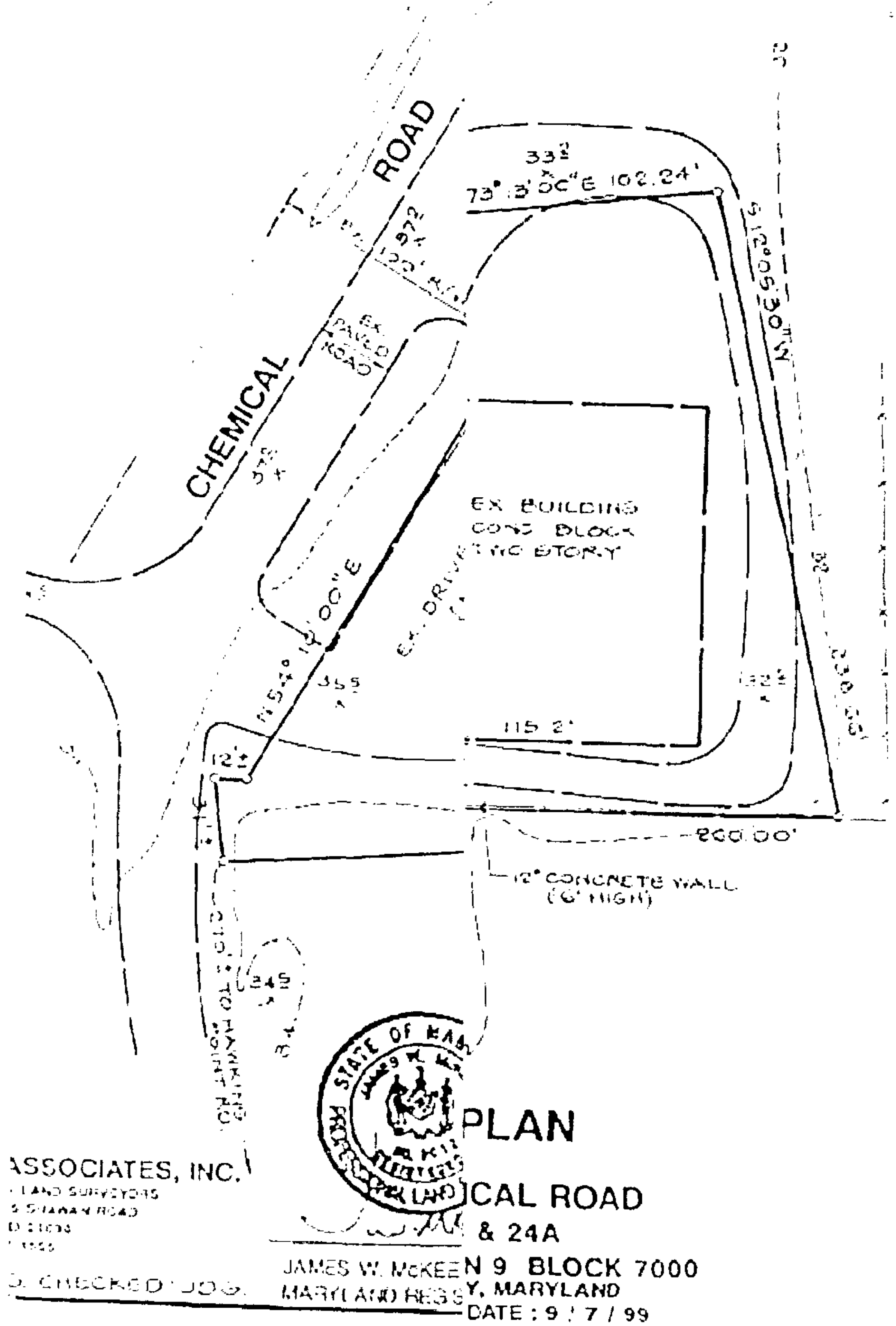
The high efficiency single stage DUCON cyclone is installed on the north side of the structure, between the structure and the existing Baltimore plant building. Solids are discharged into a drum (not shown), and hot air (with water vapor from injection of water in the bed) is vented directly from the cyclone. The particle size distribution of the silica sand in the bed is selected such that the minimum particle size is well above 10 μ, so little particle emissions from the bed are encountered. The combustion air fans are installed on the ground level at the eastside of the structure.

## 4.2 Test Facility

The Process Flow Diagram (PFD), the Material-Energy Balances, and the Piping and Instrumentation Diagrams (P&ID's) for the facility are presented.

### 4.2.1 Process Flow Diagram

Table 4-1 provides the Material and Energy Balances for the Plant in Baltimore. The table is constructed in a manner that tracks the process nodes of Figure 4-3 for the PFD and is otherwise self-explanatory.

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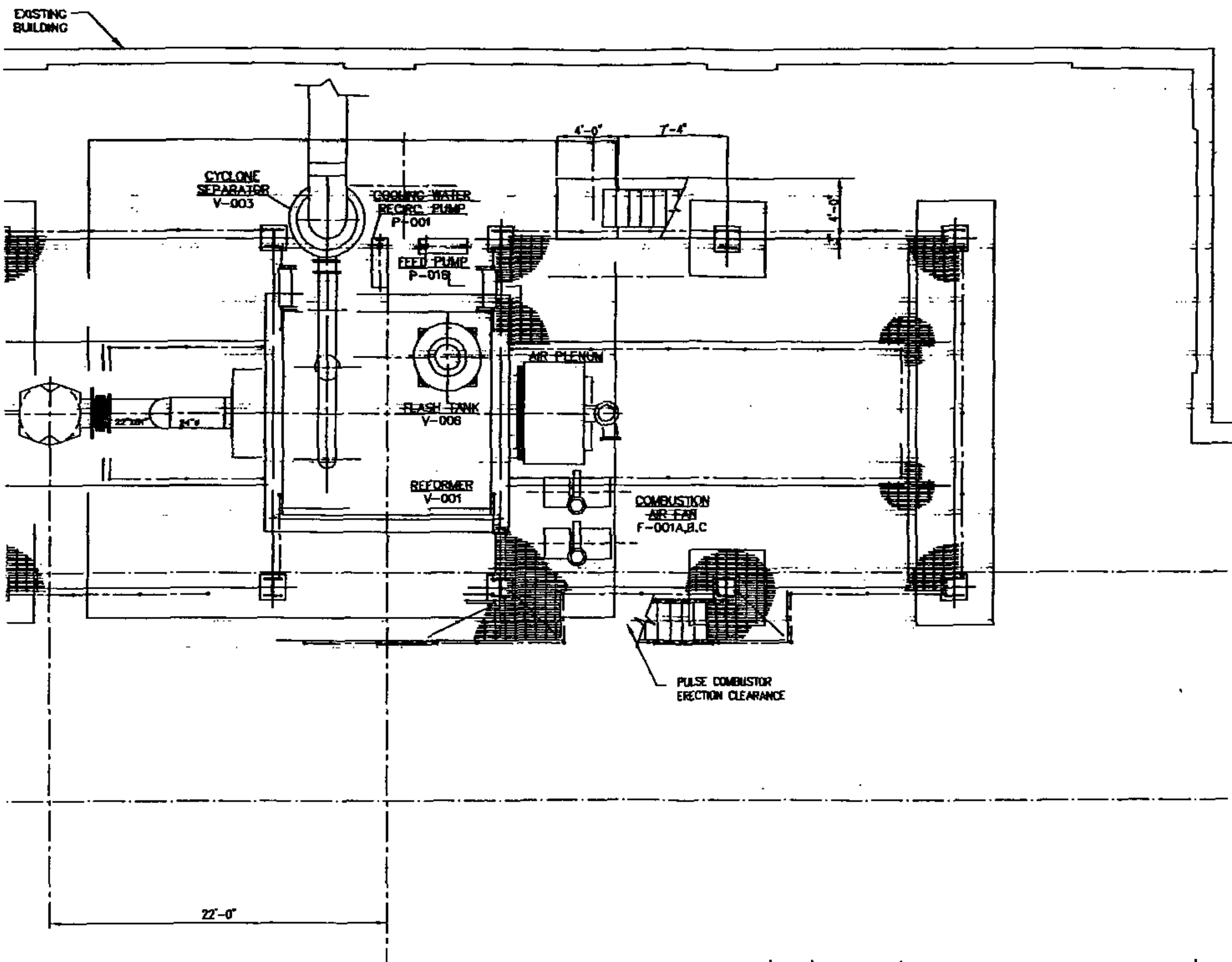


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| C | 13NOV98 | ISSUED FOR APPROVAL | HGO |
| B | 5NOV98 | ISSUED FOR REVIEW | HGO |
| A | 27OCT98 | ISSUED FOR REVIEW | HGO |

**YOUT DRAWING**

ThermoChem Inc. 6001 CHEMICAL ROAD BALTIMORE, MD 21226

DEMONSTRATION PLANT
GENERAL ARRANGEMENT
SHEET 1

INDUSTRA Engineers & Consultants
SEATTLE WA. PORTLAND OR. GREENVILLE S.C.
PROJECT NO. 11805

| SCALE | DATE | DRAWING NO. | REV. |
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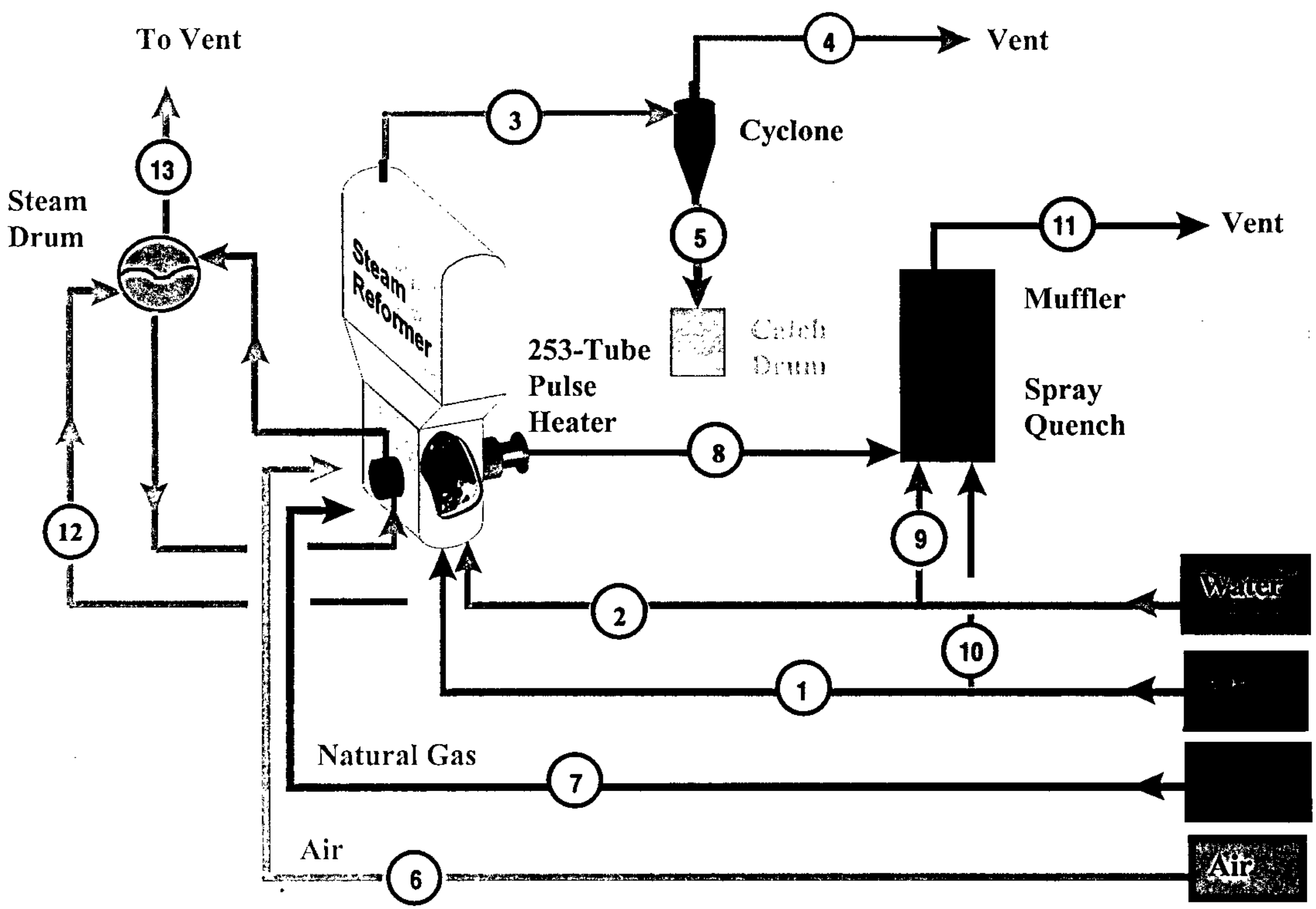



FIGURE 4-3: PROCESS FLOW DIAGRAM AND PROCESS NODES

### 4.2.2 Material Balance

Table 4-1 provides the Material Balance for the Plant in Baltimore. The table is constructed in a manner that tracks the process nodes of Figure 4-3 for the PFD and is otherwise self-explanatory.

### 4.2.3 Energy Balance

Table 4-1 provides the Energy Balance for the Plant in Baltimore. The table is constructed in a manner that tracks the process nodes of Figure 4-3 for the PFD and is otherwise self-explanatory.

### 4.2.4 Piping and Instrumentation Diagram

The Piping and Instrumentation Diagram (P&ID) outlines the controls and instrumentation used in the test facility. An ALLEN BRADLEY PLC 5/10 programmable logic controller (PLC) controlled the test facility. The PLC, in conjunction with a Fireye burner management system (BMS), tied in all the process and control loops required to operate the facility efficiently and safely. Figure 4-4 shows all the associated instrumentation utilized for the reformer including all instrumentation that was interlocked to the BMS. Figure 4-5 is the Pulse Combustor Cooling Circuit P&ID.

## 4.3 Waste Streams

No liquid waste streams will be generated, since no coal feedstock will be processed in the fluid-bed of the 253-tube pulse heater Test Facility.

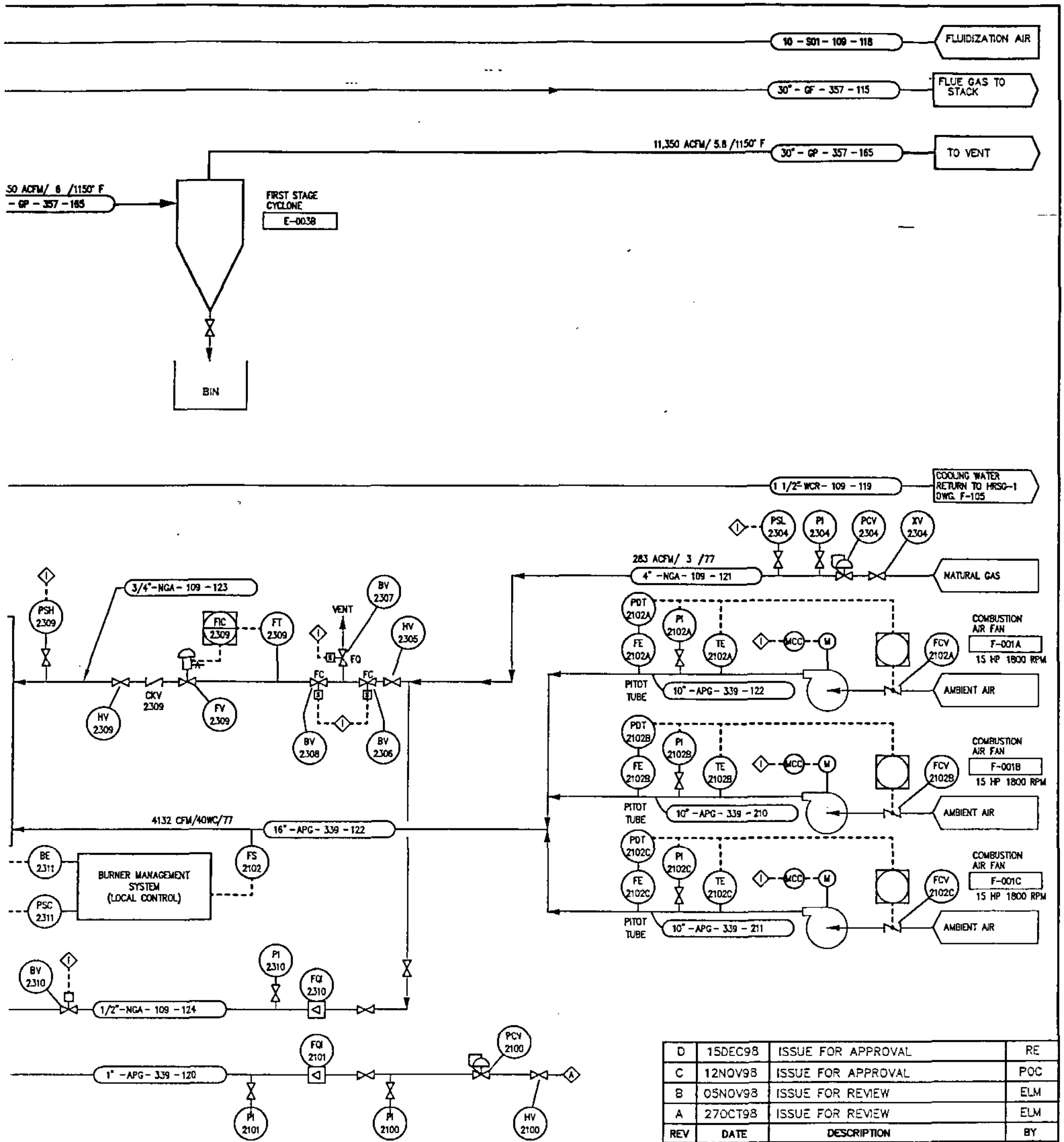
The heat load to the bed is achieved by injecting water into the sand bed to maintain the desired bed temperature at a given combustor firing rate. As shown in Figure 4-3, the water vapor (steam) leaving the cyclone with the fluidization air (node 4) is on the order of 1,800 lb/h for the firing rate case presented in the figure.

### 4.4 Test Equipment List

The Major Equipment List for the 253-tube pulse combustor test facility is provided in Table 4-2. The diesel-driven compressors are rented equipment used to provide the air for the bed fluidization during a firing test run of the full-scale pulse combustor.

ThermoChem designed the fluid-bed with support by Industra Engineers and Constructors and Javan & Walters. MTCI built the fluid bed vessel in house. The pulse heater was designed by ThermoChem, supported by MTCI, and was built by Diversified Metals.

| STREAM NO -> | | 1 | 2 | 12 | 13 |
|---|---|---|---|---|---|
| | | Air to Reformer | Wateas to Reforn | Makeup Water to Steam Drum | Steam to Vent |
| PRESSURE | PSIG | 10.5 | | 465 | 450 |
| | IN WC | | 0 | | |
| TEMPERATURE | F | 59 | 703 | 50 | 459 |
| VOLUMETRIC FLOW | GPM | | | 2.2 | |
| | SCFM | 3,228 | ,306 | | 387 |
| | ACFM | 1,879 | ,109 | | 22 |
| COMPONENT | | | | | |
| CH4 | LB/HR | | 0.01 | | |
| C2H6 | LB/HR | | 0.00 | | |
| C2H4 | LB/HR | | | | |
| C3H6 | LB/HR | | | | |
| C3H8 | LB/HR | | | | |
| H2S | LB/HR | | | | |
| CH3SH | LB/HR | | | | |
| (CH3)2S | LB/HR | | | | |
| (CH3)2S2 | LB/HR | | | | |
| H2 | LB/HR | | | | |
| CO | LB/HR | | 0.21 | | |
| CO2 | LB/HR | 7 | ,388 | | |
| H2O (v) | LB/HR | 94 | ,957 | | 1,103 |
| NH3 | LB/HR | | | | |
| O2 | LB/HR | 3,390 | ,843 | | |
| N2 | LB/HR | 11,199 | 130 | | |
| SO2 | LB/HR | | | | |
| H20 (l) | LB/HR | | | 1,103 | |
| NO | LB/HR | | ).38 | | |
| HCl | LB/HR | | | | |
| C | LB/HR | | | | |
| Na2CO3 | LB/HR | | | | |
| NaCl | LB/HR | | | | |
| Na2SO4 | LB/HR | | | | |
| Na2SO3 | LB/HR | | | | |
| NaHSO3 | LB/HR | | | | |
| Na2S | LB/HR | | | | |
| NaHS | LB/HR | | | | |
| NaHCO3 | LB/HR | | | | |
| NaOH | LB/HR | | | | |
| MF COAL | LB/HR | | | | |
| Inerts | LB/HR | | | | |
| TOTAL MASS | LB/HR | 14,689 | 318 | 1,103 | 1,103 |
| TOTAL CARBON | LB/HR | 0 | 52 | 0 | 0 |
| TOTAL SULFUR | LB/HR | 0.000 | 0 | 0 | 0 |
| TOTAL SODIUM | LB/HR | 0 | 0 | 0 | 0 |
| TOTAL CHLORINE | LB/HR | 0.0 | ).0 | 0.0 | 0.0 |
| HHV | BTU/HR | 0 | 13 | 0 | 0 |
| ENTHALPY | BTU/HR | 34,644 | -42 | -29,750 | 1,353,843 |
| TOTAL HEAT | BTU/HR | 34,644 | -55 | -29,750 | 1,353,843 |




| REV | DATE | DESCRIPTION | BY |
|---|---|---|---|
| D | 15DEC98 | ISSUE FOR APPROVAL | RE |
| C | 12NOV98 | ISSUE FOR APPROVAL | POC |
| B | 05NOV98 | ISSUE FOR REVIEW | ELM |
| A | 27OCT98 | ISSUE FOR REVIEW | ELM |

ThermoChem Inc.

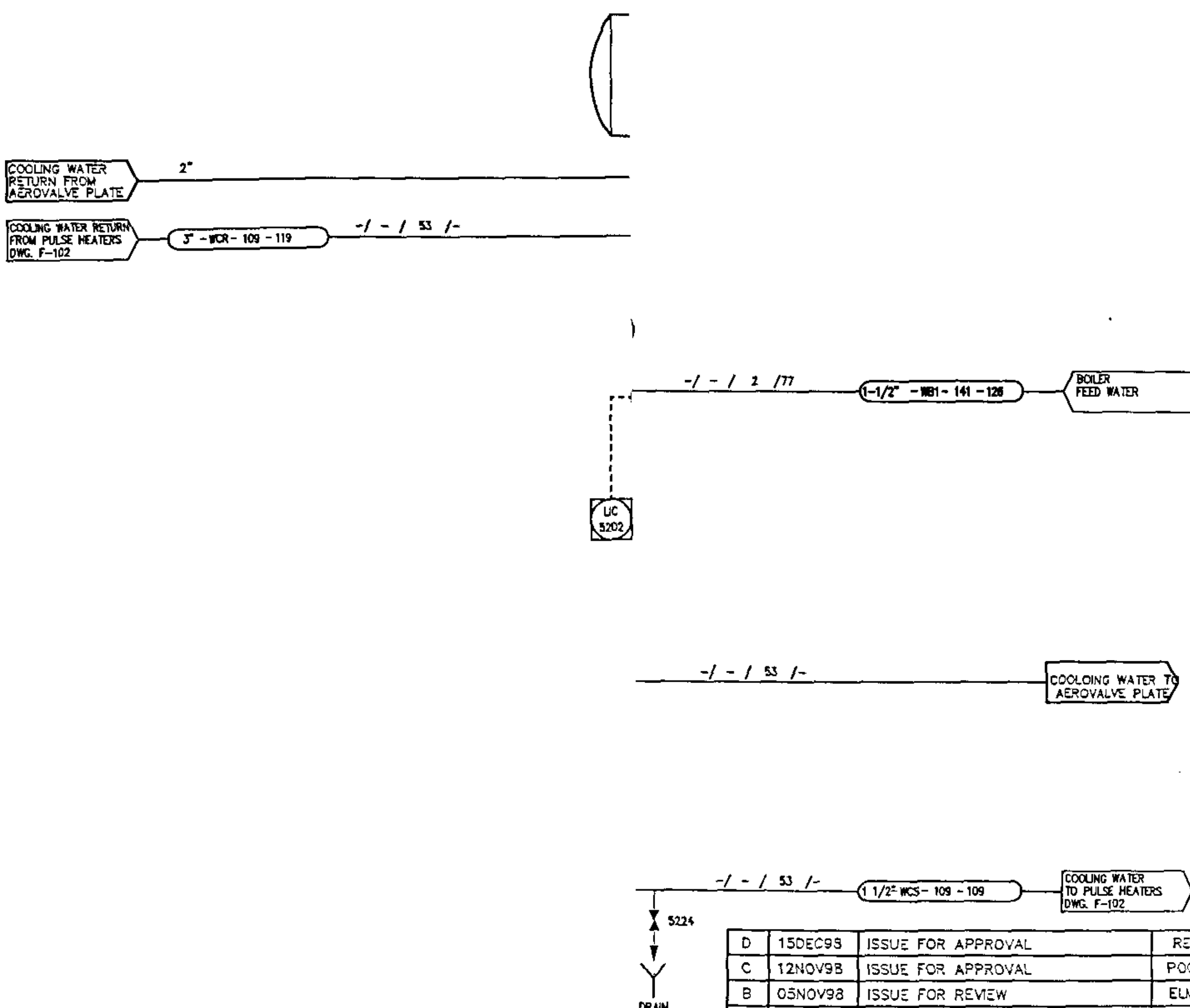
6001 CHEMICAL ROAD BALTIMORE, MD 21226

## NSTRUMENTATION DIAGRAMS

INDUSTRA
Engineers & Consultants
SEATTLE WA. | PORTLAND OR. | GREENVILLE S.C.
PROJECT NO. 11805

DEMONSTRATION PLANT
P & I DIAGRAM
REFORMER

| SCALE | DATE | DRAWING NO. | REV. |
|---|---|---|---|
| NONE | 23OCT98 | D-11805-F-102 | E |
| DR. BY | PROJ. NO. | | |
| ELM | 11805 | | |




| REV | DATE | DESCRIPTION | BY |
|---|---|---|---|
| D | 15DEC98 | ISSUE FOR APPROVAL | RE |
| C | 12NOV98 | ISSUE FOR APPROVAL | POC |
| B | 05NOV98 | ISSUE FOR REVIEW | ELM |
| A | 27OCT98 | ISSUE FOR REVIEW | ELM |

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DEMONSTRATION PLANT
P & I DIAGRAM
PRODUCT GAS HEAT RECOVERY

| SCALE | DATE | DRAWING NO. | REV. |
|---|---|---|---|
| NONE | 23OCT98 | D-11805-F-105 | E |
| DR. BY | PROJ. NO. | | |
| ELM | 11805 | | |

TRA
ltants
GREENVILLE S.C.
305

ThermoChem Contract No. 10030

Public Design Report
DOE Cooperative Agreement No.
DE-FC22-92PC92644

## TABLE 4-2: 253-TUBE PULSE HEATER QUALIFICATION TEST FACILITY MAJOR EQUIPMENT LIST

| ITEM NO. | ITEM DESCRIPTION | QTY | CAPACITY (SIZE) | DESIGN SPECS | MAT. OF CONSTRUCT. | VENDOR |
|---|---|---|---|---|---|---|
| 1 | Air Compressors (rental): | | | Pressure Rating 140 psig Nominal | N/A | Ingersoll-Rand |
| | • Large Capacity Set | 3 | 1,300 scfm | | | |
| | • Small Capacity Set | 2 | 850 scfm | | | |
| 2 | Steam Reformer Fluid Bed | 1 | 20' x 10'x 60' | ASME Code for 15 psig | Shell from Carbon Steel. Air Distribution SS 304 | |
| 3 | Cyclone | 1 | 20,000 lb/h gas flow 2,500 ppmv solids | 98% Efficiency | SS 321 | Ducon |
| 4 | 253-Tubes Pulse Heater | 1 | 25 MMBtu/Hr Max Firing Rate 55 to 65 Hz | Per Fabrication Drawings | SS 310 Tubes, SS 304 Baffle, CS Water Jacket Aerovalves, SS 317 L | |
| 5 | Quenching Duct | 1 | 4' x 10' L Pipe 215 Gallons | Standard Wall | CS | |
| 6 | Steam Drum | 1 | 215 Gallons | ASME Code Section 8 Division I Pressure 550 psig | SA 516 | Struthers Wells Corp. |
| 7 | Combustion Air Fans | 5 | 1383 scfm at 40" Water Head Each | 15 hp Motors 23" dia. Fan | Per Vendor Drawings | American Fan Company |
| 8 | Programmable Logic Controller (PLC) | 1 | 512 K Non-Volatile Memory | Allen Bradley PLC 5/10 | N/A | Allen Bradley |

## TABLE 4-3: PDU TEST EQUIPMENT LIST

| ITEM NO. | ITEM DESCRIPTION | QTY. | CAPACITY (SIZE) | DESIGN SPECS | MAT. OF CONSTRUCT. | VENDOR |
|---|---|---|---|---|---|---|
| 1 | Steam Reformer | 3 | 40-50 lbs/h throughput 8" diameter Fluid Bed Area. 14" diameter Freeboard Area | Atmospheric Pressure. Up to 1,550°F Bed Temp. (Max. 1,600°F) 5-12 s gas residence time. Fluidization Velocity 0.5 to 1.4 ft/s | SS 310 — | Built by MTCI |
| 2 | Pulse Heater | 1 | Two-Tube Pulse Combustor with 1.5" Pipe Schedule 40 in a U shaped configuration | Nominal 60 Hz Design Frequency<br>Full firing rate 200 KBtu/hr on Natural Gas | SS 310 | Built by MTCI |
| 3 | Coal Feed System | 1 | Up to 100 lb/h Feed Rate | Assembly of a Lock Hopper, a Metering Bin and a Feed Screw | CS, SS 304, and SS 310 | Tom Miles and Associates |
| 4 | Cyclones | 2 | Barrel 8" Diameter and 28" Tall | 95% Efficiency for particles ≥ 10 μ | FKI Design | FKI |
| 5 | Product Gas Thermal Oxidizer | 1 | 2' Diameter and 7.5' Long | 2 s Minimum Residence Time @ 1,800°F | Refractory Lined Carbon Steel | MTCI Built |
| 6 | Two Stage Steam Superheater | 1 | Capacity up to 150 pph Steam | From Saturated Steam at 100 psig to 1,000°F | | Electrical by Watlow, other by MTCI |

Table 4-3 presents the PDU Major Equipment List. With the exception of the Watlow supplied steam super-heater stage, most of the balance of the PDU was designed by ThermoChem/MTCI engineers and built by MTCI.

## 5.0 PROJECTED PROCESS CAPITAL

The projected process capital cost provided in this report for a commercial configuration plant is based upon projections only. The information is to be regarded as extrapolations (Scaling Factors) and budget quality engineering estimates. The cost is, of necessity, not based on actual data from a full-scale demonstration project for mild gasification of coal.

Table 5-1 presents the major equipment list for a commercial configuration plant for mild gasification of sub-bituminous coal for the Northshore Mining Company. This configuration is the most likely near term commercial plant since Northshore is still in need of such a plant. The projections are made based on a budget estimate study performed by Industra (dated July 17, 1997) which was adjusted for inflation and other considerations (scale-up from similar systems for spent liquor recovery providing new cost data since July 17, 1997).

The plant is based on a reactor with five 253-tube heaters having a nominal coal processing (mild gasification) capacity of 40 US tons per hour. For the purpose of operating cost calculations (Section 6.0), the plant was assumed to be operating at 36 US tons per hour.

Coal is fed into the steam reformer utilizing a weigh feeder and a water-cooled injection screw feeder. Ash and unreacted char are removed from the reformer via lockhoppers and a cooling conveyor.

A cold gas cleanup train is used to process the raw reformate gas from the steam reformer.

Cyclones provide fundamental particulate control, followed by a venturi scrubber to remove any remaining entrained particulate. A gas cooler with acidic pH control provides the dual purpose of cooling the gas (condensing the steam) as well as ammonia removal.

The $H_2S$ absorber contacts the relatively cool gas (125°F) with caustic to remove the sulfur as a NaHS solution. The sulfide solution will be sold to a local pulp mill as chemical makeup for the cooking process.

Finally, the reformate gas is clean and acceptable for burning as a fuel in the pulse heaters as well as in boilers for steam generation.

Table 5-1 presents the major equipment list for the commercial configuration mild gasification project. The table also indicates the items that are within the normal scope of supply from ThermoChem, and the items that are obtained by the clients' engineers via multiple-vendor quotes.

Table 5-2 presents the major equipment costs.

The plant total installed cost is shown in Table 5-3. The table presents, in addition to the Major Equipment Costs, other costs associated with the field erection of the plant.

## TABLE 5-1: MAJOR EQUIPMENT LIST

| Item No. | Item Name | Quantity Operating | Quantity Spare | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| 1 | Coal-Handling System: | | | 40 ton/h (wet) | | | |
| 2 | Bucket Elevator | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 3 | Conveyor | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 4 | Weigh Feeder | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 5 | Feed Screw | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 6 | Storage Bin | 1 | | 40 ton/h | Cylindrical with 70° Cone Bottom | Carbon Steel | Multiple Vendor Quotes |
| 7 | Reactor w/steam distributor | 1 | | 36.1 ton/h (wet) | Refractory-lined Rectangular Vessel | Carbon Steel | ThermoChem |
| 8 | Pulsed Heater w/Plenum & Aerovalves | 5 | | 253-tube 6.0 MMBtu/h each | PulseEnhanced™ | 321 SS | ThermoChem |
| 9 | Pulsed Heater Combustion Air Fan | 2 | | 9400 acfm @ 28" WC | 75 HP Blower | Carbon Steel | ThermoChem |
| 10 | Char-Handling System: | | | 13.5 ton/h (dry) | | | |
| 11 | Lock Hopper | 1 | | 1,000 lbs. char | Standard | Carbon Steel | ThermoChem |
| 12 | Cooling Conveyor | 1 | | 13.5 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 13 | Char-Slurry Mixing Tank | 1 | | 27 ton | Cylindrical with Conical Bottom | Carbon Steel | Multiple Vendor Quotes |
| 14 | Char-Mixing Tank Pumps | 2 | | 66 gpm, 7.5 hp each | Slurry-Handling | Carbon Steel | Multiple Vendor Quotes |
| 15 | Char-Mixing Tank Agitator | 1 | | 5 hp each | Medium Turbulence | Carbon Steel | Multiple Vendor Quotes |
| 16 | First Stage Cyclone | 4 | | 5000 acfm | 95% Removal | 321 SS | ThermoChem |
| 17 | Second Stage Cyclone | 4 | | 5000 acfm | 99.5% Removal | Refractory-lined Carbon Steel | ThermoChem |
| 18 | Heat Recovery Steam Generator # 1 (HRSG1) | 1 | | 26250 lb/h @ 150 psig | Unfired | Carbon Steel | ThermoChem |

## TABLE 5-1 (continued): MAJOR EQUIPMENT LIST

| Item No. | Item Name | Quantity Operating | Quantity Spare | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| 19 | HRSG1 Recirculation Pump | 1 | 1 | 60 gpm | 25 hp High Temp/ Pressure Service | Carbon Steel | ThermoChem |
| 20 | Venturi Scrubber | 1 | | 20000 acfm | S. Steel Throat | Carbon Steel Body | ThermoChem |
| 21 | Venturi Scrubber Pump | 1 | 1 | 160 gpm, 10 hp each | Slurry-Handling | Carbon Steel | ThermoChem |
| 22 | Gas Cooler Column w/pH control | 1 | | 20000 ACFM | 5.5' D X 19' H Packed | Carbon Steel | ThermoChem |
| 23 | Gas Cooler Tank | 1 | | 5000 | Cylindrical w/Dished Bottom | Carbon Steel | ThermoChem |
| 24 | Gas Cooler Heat Exchanger | 1 | | 2 MM Btu/h | Plate Heat Exchanger | Carbon Steel | ThermoChem |
| 25 | Gas Cooler Recirculation Pump | 1 | 1 | 760 gpm, 20 hp each | Centrifugal | Carbon Steel | ThermoChem |
| 26 | $H_2S$ Absorber | 1 | | 20000 acfm | 5.5' D X 24' H Packed | Carbon Steel | ThermoChem |
| 27 | $H_2S$ Absorber Recirculation Pump | 1 | 1 | 110 gpm, 2 hp each | Centrifugal | Carbon Steel | ThermoChem |
| 28 | Superheater | 1 | | 4.2 MM Btu/h | Standard | 304 SS | ThermoChem |
| 29 | Heat Recovery Steam Generator 2 (HRSG2) | 1 | | 39,000 lb/h @ 150 psig | Fired with off-gas or Natural gas | Carbon Steel | Multiple Vendor Quotes |
| 30 | Air Heater | 1 | | 9 MM Btu/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 31 | Stack | 1 | | 20000 acfm | 83' H | Carbon Steel | Multiple Vendor Quotes |
| 32 | SS Duct Work | 1 lot | | 6700 sq. ft. | 3/16" Different Sizes | 304 SS | Multiple Vendor Quotes |
| 33 | Carbon Steel Duct Work | 1 lot | | 3300 sq. ft. | 3/16" Different Sizes | Carbon Steel | Multiple Vendor Quotes |

| Item No. | Item Name | | Installation | Total Cost |
|---|---|---|---|---|
| 1 | Coal-Handling Systems: | | | |
| 2 | Bucket Elevator | 1 | 5,000 | 107,000 |
| 3 | Conveyor | 1 | 5,000 | 163,100 |
| 4 | Weigh Feeder | | 2,500 | 53,500 |
| 5 | Feed Screw | | 2,500 | 79,000 |
| 6 | Storage Bin | 3 | 12,500 | 318,500 |
| 7 | Reactor w/Steam Distributor | 4 | 110,000 | 519,020 |
| 8 | Pulsed Heater w/ Plenum & Aerovalves | 5 | 50,000 | 2,639,780 |
| 9 | Pulsed Heater Combustion Air Fan | | 13,580 | 39,080 |
| 10 | Char-Handling System: | | | |
| 11 | Lock Hopper | | 1,500 | 3,540 |
| 12 | Cooling Conveyor | | 2,500 | 53,500 |
| 13 | Char-Mixing Tank | | 950 | 6,050 |
| 14 | Char-Mixing Tank Pumps | | 5,000 | 9,080 |
| 15 | Char-Mixing Tank Agitator | | 1,000 | 3,040 |
| 16 | First Stage Cyclone | | 10,000 | 157,900 |
| 17 | Second Stage Cyclone | | 10,000 | 163,000 |
| 18 | Heat Recovery Steam Generator # 1 | 3 | 14,900 | 320,900 |
| 19 | Recirculation Pump | | 6,200 | 13,340 |
| 20 | Venturi Scrubber w/Throat | | 2,300 | 15,560 |
| 21 | Venturi Scrubber Pump | | 8,200 | 17,380 |
| 22 | Gas Cooler Column w/pH control[1] | 1 | 2,500 | 14,740 |

[1] Ammonia removal

## AJOR EQUIPMENT COSTS

| :ost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|
| | | Equipment | Freight | Installation | |
| ;50 | 1.0 | 2,500 | 50 | 1,000 | 3,550 |
| )80 | 1.0 | 4,000 | 80 | 1,000 | 5,080 |
| 320 | 2.0 | 22,000 | 440 | 6,200 | 28,640 |
| 760 | 1.0 | 13,000 | 260 | 2,500 | 15,760 |
| ;50 | 2.0 | 5,000 | 100 | 6,200 | 11,300 |
| 200 | 1.0 | 35,000 | 700 | 1,500 | 37,200 |
| ,960 | 1.0 | 708,000 | 14,160 | 24,800 | 746,960 |
| ,500 | 1.0 | 150,000 | 3,000 | 2,500 | 155,500 |
| 000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| ,000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| ,000 | 1.0 | 0 | 0 | 188,000 | 188,000 |
| )00 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| 000 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| ,000 | 1.0 | 0 | 0 | 209,000 | 209,000 |
| | | **5,333,500** | **106,670** | **755,830** | **6,196,000** |

## TABLE 5-3: PROJECT TOTAL INSTALLED COST

| Item No. | Item Description | Unit Cost: Equipment/ Material | Unit Cost: Installation/ Subcontract | Item Total Cost | Remarks |
|---|---|---|---|---|---|
| | **Direct Costs:** | | | | |
| 1 | Major Equipment | $5,440,170 | $755,830 | $6,146,000 | |
| 2 | Piping | $1,170,000 | $1,013,000 | $2,183,000 | |
| 3 | Electrical | $170,000 | $250,000 | $420,000 | |
| 4 | Instrumentation & Control | $670,000 | $530,000 | $1,200,000 | |
| 5 | Site Preparation | $20,000 | $130,000 | $150,000 | |
| 6 | Civil/Structure | $25,000 | $100,000 | $125,000 | |
| 7 | Building | $600,000 | $660,000 | $1,260,000 | |
| 8 | Operation & Startup Spares | | | $700,000 | Includes one Pulse Heater |
| 9 | 10% Escalation | | | $1,250,000 | 3-yrs since 98 Estimate |
| 10 | Land | | | $500,000 | |
| 11 | Preliminary Expenses/Project Fees | | | $2,250,000 | |
| 12 | Insurance and Permits | | | $2,100,000 | |
| 13 | Warranty & Licensing Fees | | | $1,800,000 | |
| 14 | 10% Execution Contingency | | | $1,950,000 | |
| | | | | | |
| **Direct Cost Total** | | **$8,095,170** | **$3,438,830** | **$22,084,000** | |
| | | | | | |
| **Indirect Cost:** | | | | | |
| 15 | 8% Detailed Engineering | | | $1,500,000 | |
| 16 | Project and Construction Management | | | $1,700,000 | |
| 17 | Commissioning and Start-Up | | | $650,000 | Includes Training Support |
| 18 | General & Administrative Expenses | | | $1,500,000 | |
| 19 | General Contingency | | | $750,000 | |
| **Indirect Cost Total** | | | | **$6,100,000** | |
| **PROJECT TOTAL INSTALLED COST** | | | | **$28,184,000** | |

## 6.0 ESTIMATED OPERATING COST

In this section both the initial startup costs as well as the plant operating costs are provided. The initial startup cost estimate is provided in Table 6-1 below.

**TABLE 6-1: INITIAL STARTUP COSTS ESTIMATE**

**GENERAL ASSUMPTIONS**

| | |
|---|---|
| **Years Until Construction** | 2 Years |
| **Years Until Start-Up** | 3 Years |
| **Number of Plants** | 1 |
| **Plant Capacity** | 36.1ton/h (wet coal with 25% moisture) |
| **Tons Char / Ton Coal** | 0.337 |
| **Escalation Factor** | 3% per year |
| **Start-up Equipment & Spare** | Included with Equipment Cost |
| **Start-up Type** | Initial Start-Up |
| **Briquetting/Binding Facilities** | Not Included (Northshore needs char) |

**INITIAL START-UP COSTS**

| COST ELEMENT | $ COST |
|---|---|
| Operating Labor Cost | 476,000 |
| Maintenance and Material Cost | 170,000 |
| Administrative and Support Cost | 546,000 |
| Commodities Cost: | |
| Coal Feedstock | 390,000 |
| Electricity | 330,000 |
| Initial Startup Fuel | 61,000 |
| Other Commodities* | 108,000 |
| **TOTAL INITIAL START-UP COSTS** | **2,081,000** |
| *Includes chemicals, water, waste disposal and supplies | |

Table 6-2 provides the operating cost estimates including both the fixed and variable O&M Costs.

# TABLE 6-2: OPERATING COST ESTIMATES

**GENERAL ASSUMPTIONS:**

| | |
|---|---|
| **Assumptions Date:** | March 2001 |
| **Years Until Construction:** | 2 Years |
| **Years Until Start-up:** | 3 Years (2004) |
| **Number of Plants:** | 1 |
| **Plant Capacity:** | 36.1 US ton/h (as received wet coal with 25% moisture) |
| **Tons Char / Ton Coal:** | 0.337 |
| **Escalation Factor:** | 3% per year |
| **Briquetting / Binding Facilities:** | Not Included (Northshore needs Char-Slurry & Gas only) |

**FIXED OPERATING COST:**

**Operating Assumptions:**

| | |
|---|---|
| Number of Operators/Shift | 6.67 |
| Number of Shifts/week | 4.2 |
| Operating Labor Rate/Hr (2190 hr/yr. per operator) | $15.53 |
| Annual Plant On Line Operating Hours | 7,224 |

**Fixed Operating Details:**

| **Description** | **$ Cost/yr.** |
|---|---|
| Total Annual Operating Labor Cost | 952,300 |
| Total Annual Maintenance Labor Cost | 272,000 |
| Total Annual Maintenance Material Cost | 665,000 |
| Total Annual Overhead Cost | 500,000 |
| Total Annual G&A | 433,000 |
| Total Annual Plant Administrative & Labor Support Cost | 158,000 |
| **TOTAL ANNUAL FIXED O&M COST** | **2,980,300** |

**VARIABLE OPERATING COST (Revenue):**

| **Commodity** | **Unit (As Received)** | **$/Unit** | **Quantity/h** | **$ Cost (Revenue)/h** |
|---|---|---|---|---|
| Coal Feedstock | Ton | 5.96 | 36.1 | 215.16 |
| Electricity | kW/h | 0.05 | 1805 | 90.25 |
| Other Variable Expenses[1] | Dry Ton | 1.64 | 36.1 | 59.20 |
| By-Product Gas Revenue | MMBtu | 5.00 | 284.5 | ($1,423) |
| **TOTAL ANNUAL VARIABLE OPERATING COST (for making Char)** | | | | **($1,058)** |

[1] Contingency to cover unidentified operating costs

# 7.0 OTHER COMMERCIAL APPLICATIONS

## 7.1 Introduction

*Under the Clean Coal Technology (CCT) demonstration program,* key components of the technology will be demonstrated at full commercial-scale to test commercial applicability, ability to achieve economies-of-scale, and ability to use alternative coal feedstocks. While the demonstration will test the MTCI technology for its char redunctant generation potential, the technology can also produce several other products for other market applications.

The CCT demonstration project carried out by MTCI is to qualify a single 253-tube pulse combustor heater bundle. The heater bundle is the heart of a commercial-scale steam reformer system that has broad commercial applications including:

- black liquor processing and chemical recovery;
- hazardous, low-level mixed waste volume reduction and destruction;
- coal processing for:
  - the production of hydrogen for fuel cell power generation and other uses,
  - production of gas and char for the steel industry,
  - production of solid Clean Air Act compliance fuels,
  - production of syngas that can be used as a feedstock for the chemicals industry, for power generation, for the production of high quality liquid products, and for other purposes,
- coal-pond waste and coal rejects processing for overfiring/reburning for utility $NO_X$ control; and
- utilization of a range of other fuels and wastes to produce a variety of value added products.

Recognizing that the CCT Demonstration Program is intended to expand the markets for coal and improve the competitiveness of coal in domestic markets, especially in the electric power market, a preliminary assessment of the most promising coal applications of the MTCI technology was conducted. These applications used mild gasification of coal (via the MTCI technology) to produce: (1) metallurgical coke replacement, (2) compliance coal for existing power plants, and (3) syngas for use as an industrial feedstock and power production.

It should be noted that this is a preliminary assessment of these markets based on engineering and economic data currently available for the MTCI process. Moreover, because the MTCI technology can use a variety of fuels (and wastes) to produce a broad array of products, the market potential for the MTCI technology is considerably greater than in the following three markets assessed.

## 7.2 Market for Metallurgical Coke

An additional market for the steam reformer is to process coal to produce a lower cost replacement for metallurgical coke.

Coke, a processed form of coal, is the basic fuel consumed in blast furnaces in the smelting of iron. When coke is produced in modern by-product coke ovens with equipment to recover coal chemicals, one ton of coking coal yields the following products (depending on the type of coal carbonized, carbonization temperature and method of coal-chemical recovery).

| | Per Net Ton |
|---|---|
| Blast-Furnace Coke | 1200-1400 lb. |
| Coke Breeze | 100-200 lb. |
| Coke-Oven Gas | 9500-11500 $ft^3$ |
| Tar | 8-12 gal |
| Ammonium Sulfate | 20-28 lbs. |
| Ammonia Liquor | 15-35 gal |
| Light Oil | 2.5-4 gal |

Source: *Manufacture of Metallurgical Coke and Recovery of Coal Chemicals* (Chapter 4), in The Making, Shaping and Treating of Steel, Association of Iron and Steel Engineers.

Approximately 1,200-1,400 pounds of coke are produced from each short ton of coal, and 1,00 pounds of coke are needed to process one ton of pig iron. This processing represents more than 50% of an integrated steel mill's total energy use.

### 7.2.1 Metallurgical Coke Production and Consumption

Integrated metallurgical coke production in 1996 was approximately 18.5 million short tons[1]. Although blast furnace metallurgical coke consumption has declined by almost 1.8 million short tons from 1995 (to 16.7 million tons), there remains a shortage of coke from integrated mills of over 4 million tons. As a result of the planned closing of several coke plants, the shortfall has risen to 265,000 tons in 1998 and an additional 900,000 tons in 1999. This will bring the total shortfall to over 5 million, which is expected to be met by domestic merchant coke plants.

Breeze, a lower quality coke, is also utilized in the iron and steel industry. However, in the U.S., less than 1 million short tons of breeze are consumed. In addition, although the large majority of coke is utilized in blast furnaces, some (less than 10%) are consumed in foundries (U.S. Department of Commerce, Manufacturing Consumption of Energy, 1994).

### 7.2.2 State of Metallurgical Coke Industry

Today, there are 25 active domestic coke plants in 11 states, of which 14 are owned/operated by an integrated steel company, and 11 are merchant coke plants. Figure 7-1 depicts the location of these plants that are primarily in the Midwest and South Atlantic regions; there is also one plant located in Utah and two in New York.

The metallurgical coke industry is confronting challenges on several fronts: (1) displacement of raw steel production from integrated steel mills by increased production from mini-mills that require no coke in their electric arc furnaces, (2) improvements in blast furnace and coke-making technologies that result in less coke being required, (3) increased imports of semi-finished steels, and (4) tightening of environmental requirements applicable to coke-making plants.

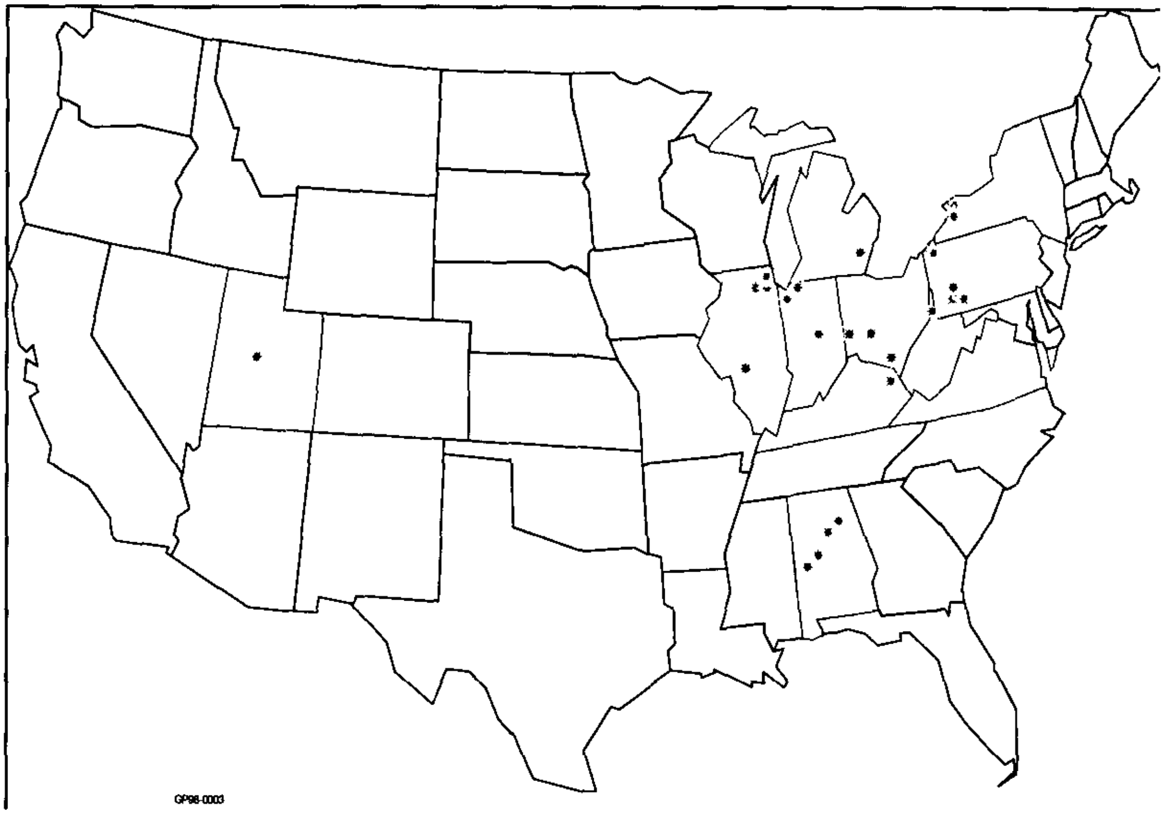



**FIGURE 7-1: LOCATION OF COKE PLANTS**

These pressures only compound the effects of aging on coking facilities - 25% of which are over 40 years old (Figure 7-2). As a result, it is estimated that 12 million tons of coking capacity may have to be replaced over the next 20 years. Tighter environmental regulations, under the Clean Air Act Amendments of 1990 to control emissions during the charging, coking, discharging (pushing), and quenching of coke, threaten to accelerate plant closures that would reduce production capacity by 30 percent by the year 2003[2].

The decline in coking capacity is evident in coal consumption trends (see Figure 7-3). In 1996, 32 million short tons of coal were utilized to produce coke, significantly lower than the 37 million short tons consumed for coking in 1987. Coal use for coke production has been declining since the late 1980s and is expected to continue to decline; by 2010 it is projected that only 26 million short tons of coal will be processed into coke (U.S. Department of Energy, Energy Information Administration).

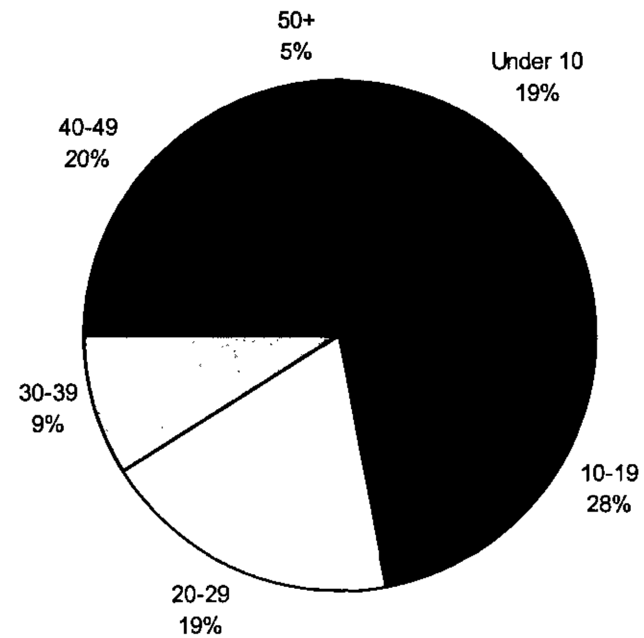
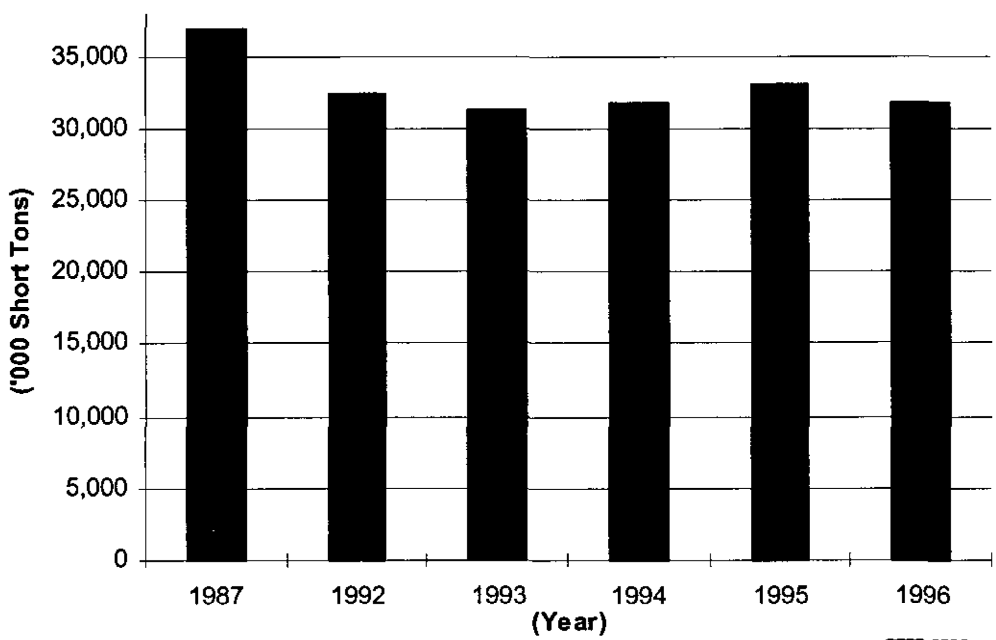



**FIGURE 7-2: BATTERY AGE BY TONNAGE PER YEAR**

**FIGURE 7-3: COAL CARBONIZED AT COKE PLANTS**



### 7.2.3 Preliminary Market Assessment

The Steel Industry Roadmap for the Future indicates a need " . . .to find more cost-effective methods of producing high quality metallurgical coke . . .". While additional examination of the chemical and physical properties is necessary, it appears that the MTCI technology can produce a high quality char to which a binder can be added and the product formed into briquettes that is a cost-effective substitute for coke in iron and steel production processes.

Prices of delivered coal to coke plants are nearly double that for coal provided to industrial users and electric utilities. The average price of coal receipts at coke plants in 1996 was $47.33/short ton, which is significantly higher than the price of coal delivered to industrial users - 32.32/short ton, and the average price of steam coal delivered to electric utilities - $26.45/short ton (see Table 7-1).

**TABLE 7-1: U.S. AVERAGE PRICE OF COAL DELIVERED ($/Short Ton)**

| *Type of Plant* | *1987* | *1992* | *1993* | *1994* | *1995* | *1996* |
|---|---|---|---|---|---|---|
| Coke Production* | 46.55 | 47.92 | 47.44 | 46.56 | 47.34 | 47.33 |
| Industrial | 33.71 | 32.78 | 32.23 | 32.55 | 32.42 | 32.32 |
| Electric Utilities | 31.83 | 29.36 | 28.58 | 28.03 | 27.01 | 26.45 |

Average prices include insurance and freight.
* Average prices include insurance, freight and taxes
*Source: U.S. Department of Energy, Energy Information Administration*

When examined on a regional basis (see Table 7-2), the highest average prices for coal delivered to coke plants is in the East North Central Census region ($51.93/short ton in Indiana) and the East South Central Census regions ($49.37/short ton in Alabama).

Because of the high price of coking coal and the increasing cost of processing the coal to coke, coke prices continue to rise. Industry estimates are that the purchased price of coke (from merchant plants) in the U.S. ranges from $95-115/ton; delivery and freight charges are additional and vary widely.

**TABLE 7-2: AVERAGE PRICE OF COAL DELIVERED TO COKE PLANTS**
**($/Short ton)**

| | Electric Utility | Industrial Plant | Coke Production* |
|---|---|---|---|
| Alabama | 36.39 | 40.15 | 49.37 |
| Indiana | 24.67 | 31.76 | 51.93 |
| Ohio | 32.31 | 35.28 | 44.98 |
| Pennsylvania | 34.06 | 33.84 | 45.16 |
| U.S. Total | 26.45 | 32.32 | 47.33 |

Average prices include insurance and freight.
* Average prices include insurance, freight and taxes.
*Source: U.S. Department of Energy, Energy Information Administration*

Based on preliminary estimates, the MTCI technology can produce a high quality char that, when a binder is added and the product is formed into briquettes, is suitable as a substitute for coke in iron and steel operations. It can also produce a breeze quality product. Even with the added costs for binders and bricquetting, the cost of producing high quality coke substitutes is less than $55/ton (at 20% ROI). This cost assumes a small MTCI plant (<50 wet tons coal/hour) that does not take advantage of economies of scale. This cost is approximately 50 percent less than current merchant plant prices ($95-115/ton) for conventional coke. In addition, the MTCI technology is significantly cleaner and more efficient than current coking processes. These attributes would (1) counter any additional price increases arising from compliance with Clean Air Act requirements (likely incurred by conventional coking operations), and (2) provide a lower cost feedstock for the U.S. iron & steel industry, and thereby facilitate international market competitiveness.

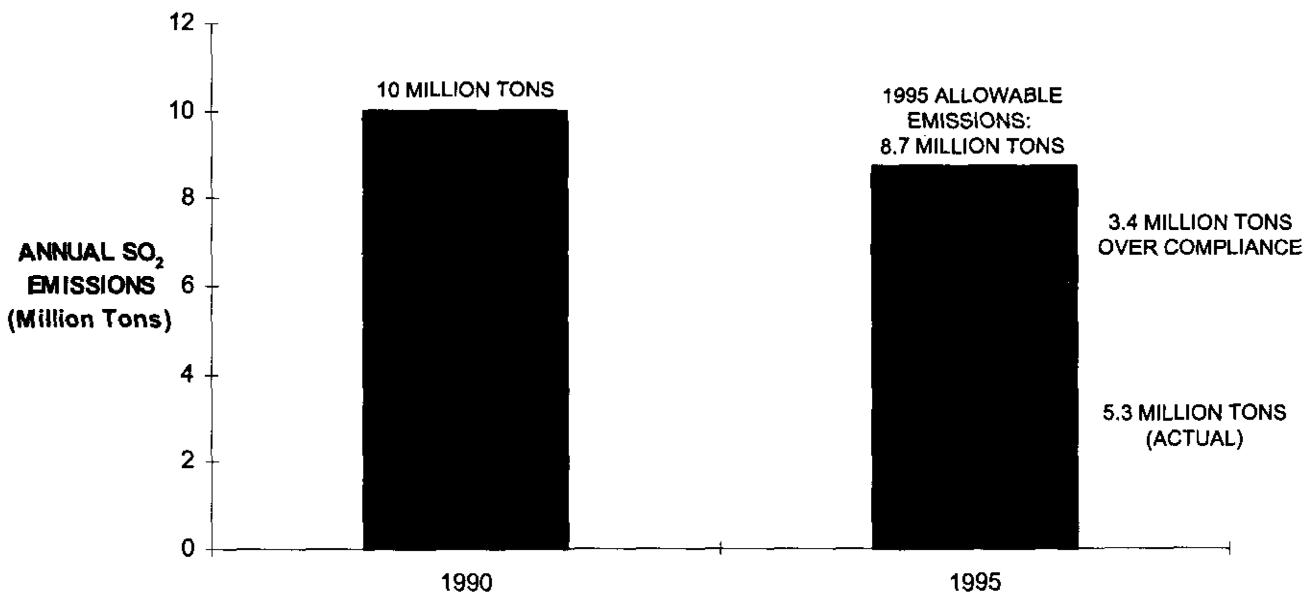
## 7.3 Market for Compliance Coal

The acid rain provisions (Title IV) of the Clean Air Act Amendments of 1990 require existing coal-fired power plants to reduce their $SO_2$ emissions in two phases, in 1995 and 2000. To comply with the 1995 requirements, many power plants switched coals to those with a sulfur content that complies with the emissions target (below 2.5 lbs. sulfur/MMBtu); this is also known as "compliance coal." Although many utilities are still assessing options for compliance with the more stringent year 2000 requirements (1.2 lbs. sulfur/MMBtu), it is expected that coal switching to a low sulfur coal will again be the dominant compliance method. Coal switching is a popular compliance choice due to its relatively low cost because a capital investment in flue gas desulfurization (FGD) or other $SO_2$ control technology is not required.

### 7.3.1 Title IV Requirement

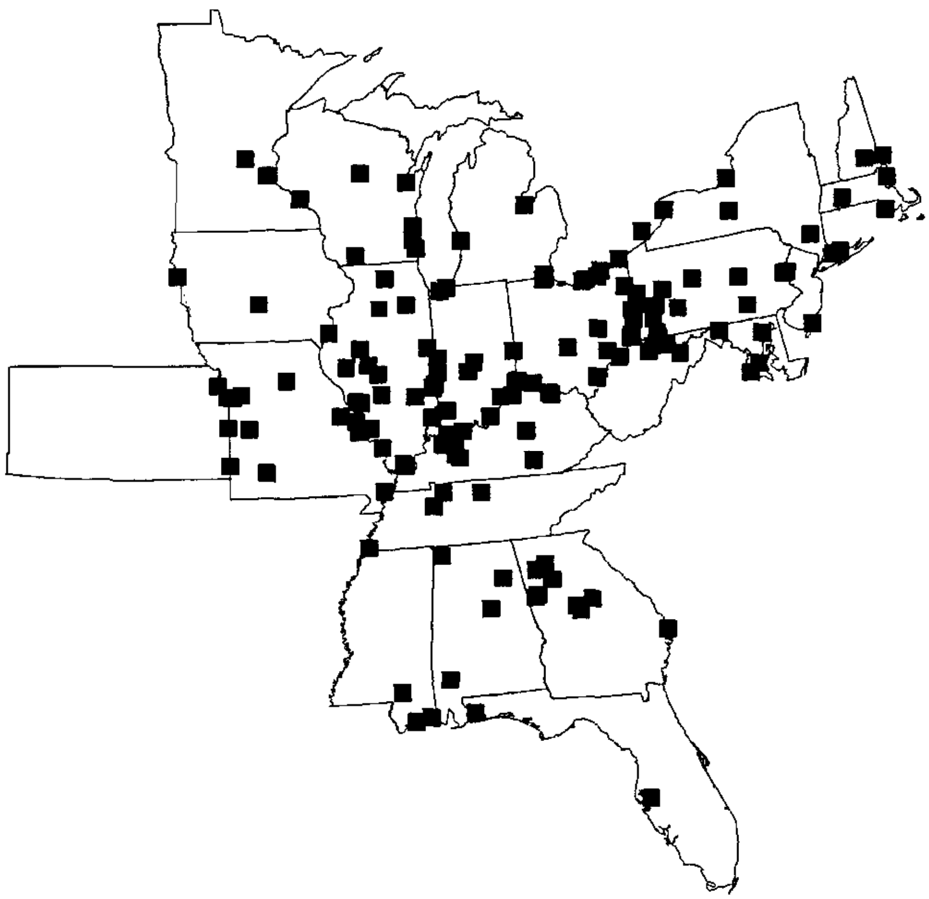
The first phase of Title IV, effective January 1, 1995, required 261 affected generating units at 110 plants to reduce their collective $SO_2$ emissions to 8.7 million tons (see Figure 7-4). Each "affected" unit was allocated based on its

**FIGURE 7-4: PHASE I ALLOWABLE $SO_2$ EMISSIONS UNDER TITLE IV**




baseline fuel consumption during the 1985-1987 period. In Phase I, allowances were allocated to each unit at the rate of 2.5 lbs. of $SO_2$/MMBtu times its baseline fuel consumption. Units that used particular control technologies to meet their Phase I reduction requirements could receive a two-year extension for compliance. The CAAA also allows for a special allocation of 200,000 annual allowances per year - for each of the 5 years of Phase I - to power plants that are located in Illinois, Indiana and Ohio. As illustrated Figure 7-5, these Phase I affected units were scattered across 21 states, with the majority in the Midwest and

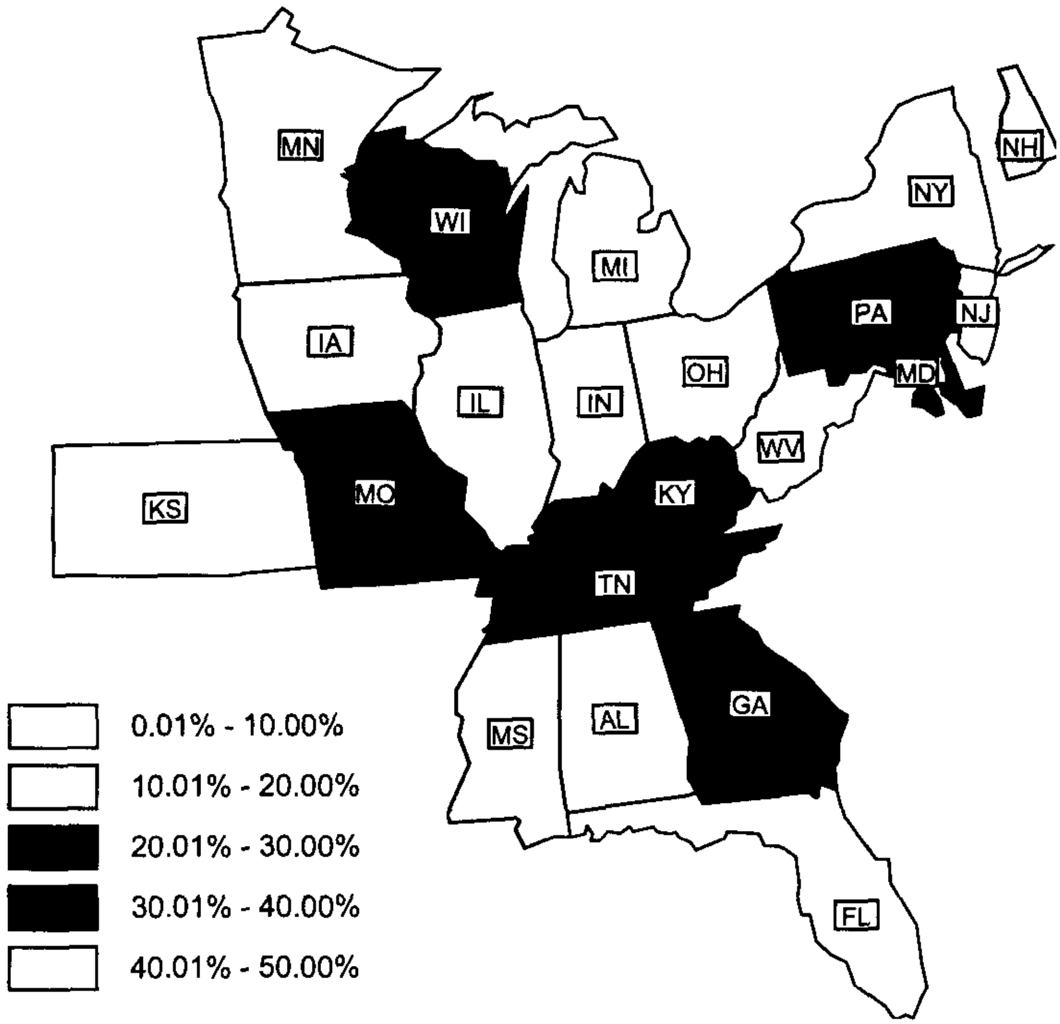
**FIGURE 7-5: PHASE I AFFECTED POWER PLANTS**



Central Atlantic states. Figure 7-6 depicts how the proportion of in-state capacity affected by Phase I compliance varied. In particular states - Indiana, Ohio and West Virginia - more than 40 percent of the nameplate capacity was classified as Phase I affected units.

The second phase becomes effective on January 1, 2000. It requires approximately 2000 fossil fuel generating units greater than 25 MW in size (including the 261 Phase 1 units) to reduce their emissions to a level equivalent to the product of an emissions rate of 1.2 lbs. of $SO_2$/MMBtu times the average of their 1985-1987 fuel consumption.

## FIGURE 7-6: PERCENTAGE OF NAMEPLATE CAPACITY AFFECTED BY PHASE I COMPLIANCE




### 7.3.2 Consumption of Compliance Coal

Table 7-3 summarizes the $SO_2$ compliance methods for Phase 1 units - those coal-fired generating units specifically identified in Title IV for Phase 1 compliance. Fifty-two percent (136 units) switched to or blended with a low sulfur coal, accounting for 59 percent of the $SO_2$ emissions reductions achieved in 1995[3]. These units consume approximately 637 million tons of coal each year; sales of compliance coal continue to rise.

## TABLE 7-3: PROFILE OF COMPLIANCE METHODS FOR PHASE 1 UNITS

| Compliance Method | Number of Generators | Affected Nameplate Capacity (MW) | Percentage of Total Nameplate Capacity Affected by Phase I | Percentage of $SO_2$ Emission Reductions in 1995[a] |
|---|---|---|---|---|
| Fuel Switching and/or Blending | 136 | 47,280 | 53 | 59 |
| Obtaining Additional Allowances | 83 | 24,395 | 27 | 9 |
| Installing Flue Gas Desulfurization Equipment (Scrubbers) | 27 | 14,101 | 16 | 28 |
| Retired Facilities | 7 | 1,342 | 2 | 2 |
| Other | 8 | 1,871 | 2 | 2 |
| **Total** | **261** | **88,989** | **100** | **100** |

[a] Base year of 1985 was used to calculate $SO_2$ emissions reductions.
Source: Energy Information Administration, 1997, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, DOE/EIA-0582 (97) (March).

For Phase II, 35% of 116 utilities surveyed in 1996 indicated that they planned to continue (or to increase) their use of compliance coal to meet emissions targets. Relative to other compliance options - installing scrubbers, repowering to natural gas, and/or purchasing allowances - use of compliance coal remains the lowest-cost.

Several factors determine the cost of utilizing compliance coal as the option to meet the Phase II requirements. In addition to the cost of the coal, fuel-handling equipment must be upgraded. Because power plants are designed to burn a particular type of coal, switching to a compliance coal requires some equipment and procedural (O&M) alterations to maximize performance. Moreover, due to its lower heat content, a greater volume of compliance coal is consumed to generate commensurate (pre-switching) amounts of power. These higher volumes impact fuel storage requirements, fuel handling equipment and can result in larger quantities of particulate matter being emitted.

### 7.3.3 State of Compliance Coal Industry

In Phase I, several affected plants over-complied in anticipation of the stricter limits to be imposed in Phase II. As a result, the price of $SO_2$ allowances, and the amount of trading activity, was considerably less than expected. As Phase II approaches, however, the price of $SO_2$ allowances has almost doubled from \$87/ton in September 1996 to \$173/ton in September 1998. Plants that used this option to comply with Phase I are now reevaluating the economics of their decisions. For instance, on November 12, 1998, Illinois Power, a utility that previously purchased allowances to meet Phase I commitments, announced that it would use compliance coal as of January 2000.

As depicted in Figure 7-5, Phase I-affected plants are located primarily in the Midwest and Eastern regions of the U.S. The largest sources of compliance coals are the Powder River Basin (located in Montana and Wyoming), and Central Appalachian (eastern Kentucky, southern West Virginia and Virginia). The current delivered prices[4] for these coals are:

| | |
|---|---|
| Powder River Basin | \$20.45 - 23.14/ton |
| Central Appalachian | \$37.93-40.63/ton |

The cost of transporting coal from the mine to the end user can add as much as 50%, and on average about 30%, to the price of low sulfur coal. However, as a result of investments made in rail networks, the average cost of shipping coal from mine to power plant has decreased. Consequently, the delivered price of compliance coal is projected to continue to decline at a rate of 1.3% annually through 2020. However, for Phase I-affected plants, transportation costs fell by only 4% compared to the average decrease of 19% for all coal deliveries. The cost of Powder River Basin and Central Appalachian Coals given above include the cost of transportation.

The MTCI technology can produce a high BTU, low sulfur coal with the following specifications:

- HHV, Btu/lb. - 12,731
- Sulfur content - 0.13%
- Moisture - 0.03%
- Ash - 11.98%

As compared to low sulfur coals used today by electric utilities, the MTCI product is more desirable. In general, the MTCI fuel has lower sulfur and moisture contents, a higher heating value and a similar ash content than coal used today. On average, all coals used today for electric power production have a sulfur content of just over 1%, a heating value of 0.17% (but more typically 0.5%), heating values averaging 8,500 Btu/lb. and ash contents of about 10%.

Based upon a preliminary economic assessment, it is estimated that the MTCI technology can produce a Phase II compliance fuel substitutable for combustion in current electric utility boilers at between $25.55 and $28.10/ton (at 15% and 20% ROI respectively) not including transportation costs. Assuming an additional 25% cost for transportation to the utility site, the resulting sales price of $31.94-$35.13/ton would be very competitive with Central Appalachian coal, but not very competitive with Power River Basin coal. Central Appalachian accounted for 450 million of the 1.06 billion tons produced in the U.S. in 1996. In addition, since the MTCI technology product is higher quality than most low sulfur coals, utilities may be willing to pay higher prices for it.

### 7.4 Market for Synthesis Gas in Power Production

Synthesis gas can be used instead of natural gas or oil in combustion turbines to produce electric power. At present, three U.S. power plants convert coal to syngas via gasification in the Clean Coal Technology Demonstration program. In addition, several industrial (petrochemical) sites are (will be) using refinery bottoms and petroleum coke as feedstocks to a gasifier to produce electricity and other chemical byproducts. The MTCI technology can also produce synthesis gas from coal for use in combustion turbines to produce electric power.

Several market opportunities exist for the use of the MTCI technology for power production. These include (1) new capacity, (2) replacement capacity, and (3) compliance capacity. Each opportunity is discussed in the following.

At present 95,300 megawatts (MW) of combined cycle and combustion turbines in the power sector are fueled by natural gas. These units generate over 80 billion kilowatt-hours, and consume 2.98 trillion cubic feet of natural gas (approximately 3 Quads).

Natural gas is currently the preferred fuel for new electric generating capacity (peaking/intermediate and baseload). This is because: (1) current fuel costs are relatively low, and they comprise 93% (projected to be reduced to 88% by 2005 with the use of advanced NGCC technologies) of the operational costs for a natural gas combined cycle (NGCC) facility; (2) the capital cost of combined-cycle plants is low and the time to install them is relatively short thereby reducing up front capital costs and producing revenues more quickly than other power options; (3) the efficiency of combined cycle plants is high and improving, and (4) the environmental issues associated with gas use are fewer than most economically viable options.

### 7.4.1 New Capacity

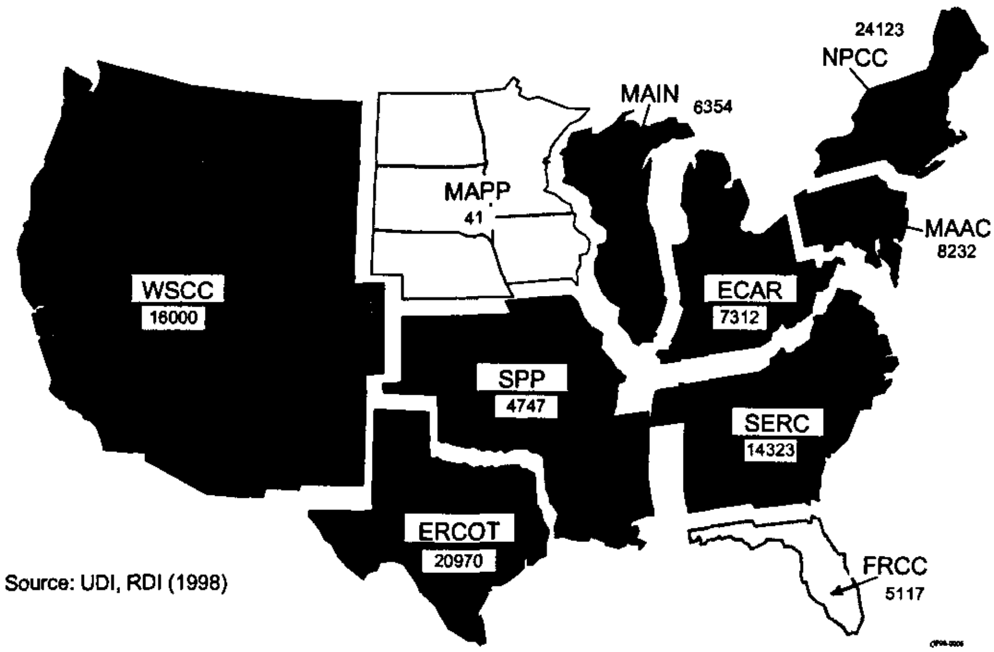
At the end of 1996, 748 GW of electric capacity was operational in the U.S. Of this, 15 GW was combined cycle, 28 GW was natural gas fired cogeneration, 80 GW was combustion turbine/diesel power and 138 GW was oil, gas and dual-fired steam generation. According to the EIA, a 1.2%/year increase in electricity generating capacity is expected during the period 1996-2020. If this growth rate holds true, an additional 403 GW of new capacity will be built in this time frame. It is projected that 85% of all new electric generation capacity during this time period will come from gas turbines and combined-cycle systems. Approximately 180 GW of new gas-fired capacity is expected to be added by 2005. Since the MTCI technology will not be commercially available to be considered for the plants to be in operation by 2005, the best market opportunity rests with the new capacity that will be built between 2006 and 2020 -- 163 GW.

As a result of the dramatic increase in natural gas-based power generation that is forecast, natural gas consumption for electric generators is expected to grow from 2.98 TCF in 1996 to 9.85 TCF in 2020. Of this, approximately 4.25 TCF of additional gas demand will result from the addition of new gas-fired power plants *between 2006 and 2020. This is the market potential for the MTCI technology, if* it can compete economically with natural gas during that time frame.

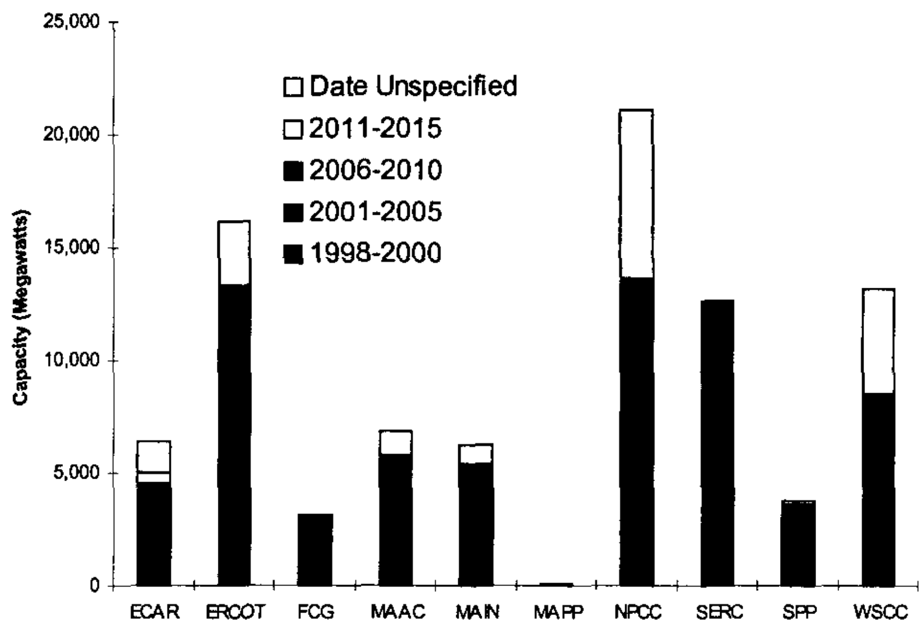
As of September 1998, announced future electric generation capacity additions *totaled 107,500 MW, of which 89,300 MW (>85%) was gas-fired capacity for* baseload and intermediate/peaking applications, in both combined cycle and simple cycle modes[5]. In 2015 there is projected to be 118,000 MW of natural gas combined cycle (NGCC), to serve both new electric demand (intermediate and peaking) and displace retired steam turbines. This represents a growth of 81,000 MW from 1995. The Gas Research Institute (GRI) projects 62,000 MW of new gas-fired capacity between 1995 and 2015, for total gas-fired electric generating capacity in 2015 of 327,600 MW.

As shown in Figure 7-7, new gas-fired capacity additions have been announced for all National Electric Reliability Council (NERC) regions except MAPP with the most additions announced in Texas (ERCOT), New England (NPCC), South Atlantic (SERC), and the West (WSCO). Most of the gas-fired capacity (61%) is proposed for the 1998-2000 period (see Figure 7-8). Given that MTCI is not yet commercially available, it cannot compete with the largest share of announced gas-fired capacity additions. However, the MTCI technology may be an option for 15,800 MW (18%) of gas-fired capacity planned for 2001-2005. More likely, because of the stage of development of the technology, the best opportunity for the technology is for the 18,400 MW (21%) of announced new generation without a projected on-line date.

## FIGURE 7-7: ANNOUNCED TOTAL CAPACITY (MW) ADDITIONS BY NERC REGION (as of Sept. 1998)




## FIGURE 7-8: PROPOSED INSTALLATION DATES FOR ANNOUNCED GAS-FIRED CAPACITY ADDITIONS, BY NERC REGION (1998-2015)

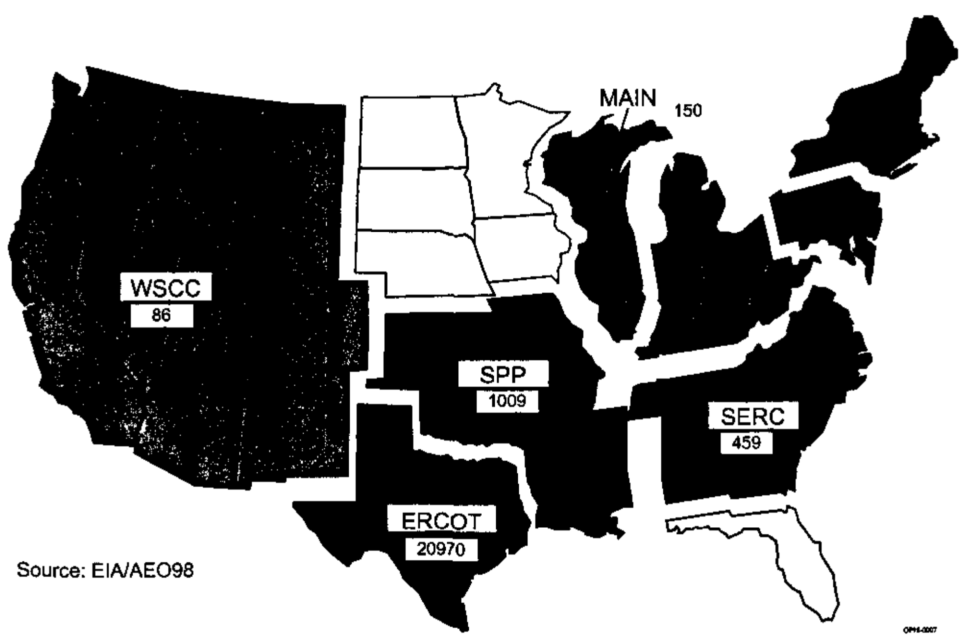


### 7.4.2 Replacement Capacity

Another market niche for the MTCI technology may be replacement capacity. Over the next 22 years (1998-2020) 105.7 GW of current electric generating capacity will be 50 years old and older and are prime candidates for replacement or refurbishment and therefore are opportunities for the MTCI technology.

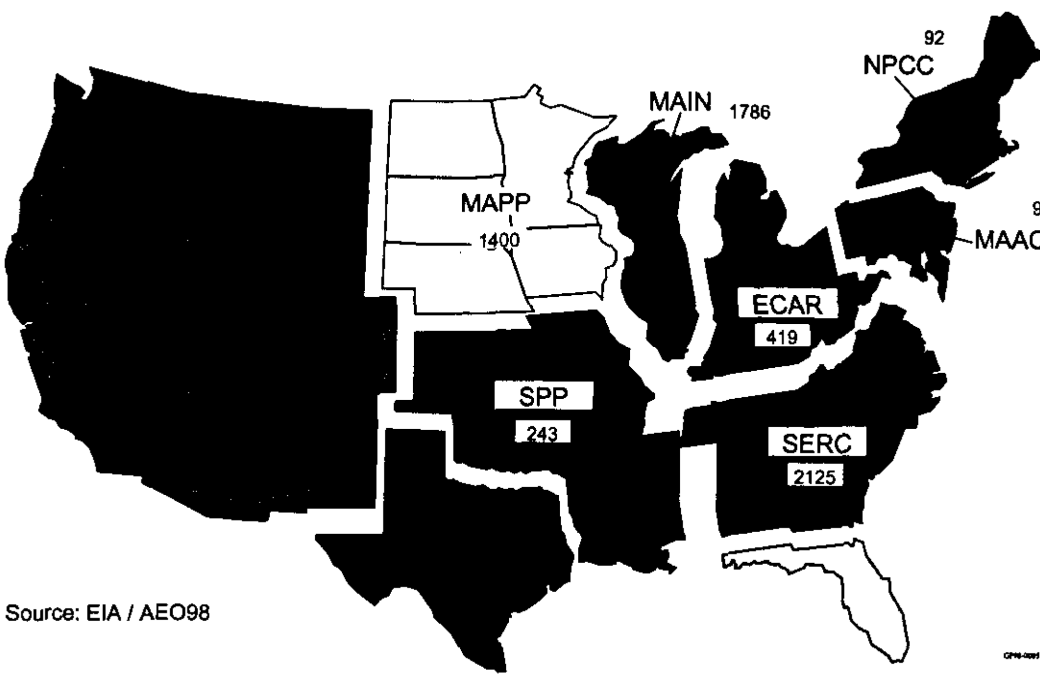
**Gas:** Approximately 3 GW of natural gas-fired capacity will reach an age of 50 years or older by 2020. Of this, more than 930 MW of gas-fired capacity (16 plants) will be a candidate for retirement/replacement between 2001-2005 and an additional 1,900 MW after 2005. These retirement/replacement dates may be accelerated if a unit is in a competitive power market. In those instances the lower syngas fuel cost provided by MTCI may permit that plant to continue operating. As shown in Figure 7-9, most of this gas-fired capacity is located in two regions: ERCOT (1,533 MW) and SPP (1,009 MW). Since fuel cost will be an important variable in the technology chosen to replace this capacity (since fuel represents about 93% of NGCC operating costs), the MTCI syngas could be an alternative, if it can produce a competitively priced fuel.

**FIGURE 7-9: LOCATION OF 1998-2020 GAS-FIRED RETIREMENT CAPACITY (MW)**



**Coal:** For coal-fired capacity, 806 MW (13 units) are slated for retirement between 1998 and 2010. Then, 100 MW (2 plants) are candidate for retirement/replacement by 2015 and an additional 2,786 MW (4 plants) by 2020. These retirement/replacement dates may be accelerated if a unit is in a competitive power market. In those instances the lower syngas fuel cost provided by MTCI may permit that plant to continue operating. As shown in Figure 7-10, most of the candidate coal retirement capacity is located in SERC (2,125 MW), MAIN (1,786 MW), and MAPP (1,400 MW), all regions with easy access to coal supplies.

**FIGURE 7-10: LOCATION OF 1998-2020 COAL-FIRED RETIREMENT CAPACITY**




Source: EIA / AEO98

### 7.4.3 Compliance Capacity

In addition to the Title IV/$SO_2$ requirements discussed in Section 7.3, there are several other environmental requirements confronting the power industry. In particular, the Ozone Transport Rule and the Kyoto Protocol, that call for significant reductions in nitrogen oxide ($NO_X$) and greenhouse gas (GHG) emissions, respectively. While coal-powered electricity generation produces the majority of these emissions (from the power sector), if this coal was converted to syngas these emission levels decline substantially while maintaining coal production.The U.S. Environmental Protection Agency (EPA) estimates that over 196,000 MW (642 units) of coal-fired capacity in the 22 state region targeted by the Ozone Transport Rule ($NO_X$ SIP Call) would be required to install selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) [6]. This would reduce $NO_X$ during the 5-month ozone season to 0.15 lbs./MMBtu. Resource Data International estimates that up to 273,000 MW of capacity would be required to install control technologies over the next ten-years.

### 7.4.4 Preliminary Market Assessment

Based on this preliminary market assessment, the MTCI-produced syngas could be used in the following markets, if it is economically competitive:

| Market | Size (MW) |
|---|---|
| New capacity | 163,000 |
| Gas replacement capacity | 1,900 |
| Coal replacement capacity | 4,592 |
| Compliance capacity | 196,000-273,000 |

With escalating natural gas prices, EIA projects that the total cost of advanced NGCC-generated electricity will increase from 31 mills/kWh in 2005 to 32.4 mills/kWh in 2020. This reflects the projected increase in natural gas prices to electricity suppliers - estimated to increase 0.7% per year, from $2.70/thousand cubic feet in 1996 to $3.22/thousand cubic feet in 2020.

In comparison, the MTCI syngas price would be between $2.73 and $4.50/MMBtu assuming a minemouth plant using $5.00/MMBtu coal for a large and small plant respectively. More likely, because of the high costs of transporting syngas and the difficulty in building transmission lines, MTCI plants will have to be located near an already existing transmission system. This will necessitate shipping coal to the plant site and paying a transmission fee. If it is assumed that these added costs are equivalent to doubling the cost of coal fed to the plant (to $10/MMBtu), it is estimated that syngas costs of between $3.41 and

$5.32/MM Btu would result. Considering these estimates, except in regions of the U.S. where natural gas prices are very high (e.g., California, Indiana, Ohio, Pennsylvania, some of the New England states, and a few other places) the MTCI technology may not be economically competitive as a syngas producer for electric power production.

## 7.5 Synthesis Gas for Industrial Feedstocks

Industrial consumers currently use natural gas converted to syngas as a feedstock to make a wide variety of products. Based on its chemical properties, syngas produced by MTCI may be able to compete in several of these markets for industrial feedstocks.

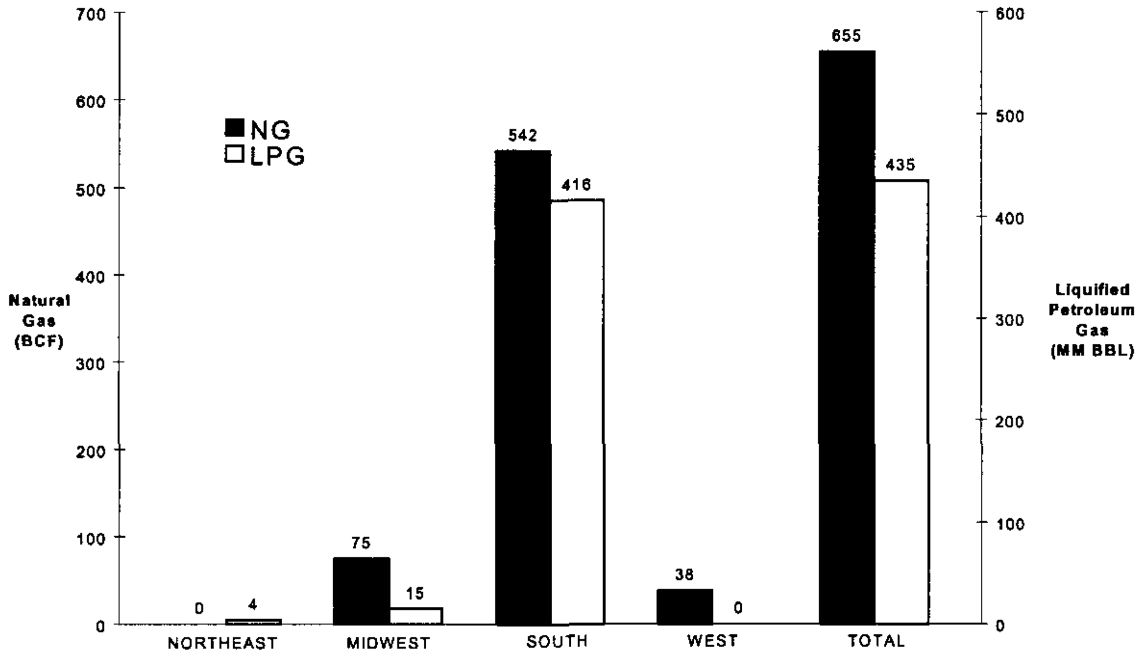
### 7.5.1 Syngas Consumption for Industrial Feedstocks

In 1994, 655 billion cubic feet of natural gas and 435 million barrels of liquefied petroleum gas (LPG) were utilized in the U.S. as industrial feedstocks. Of this, 83% of the natural gas and 96% of the LPG were used in the South Census region, primarily in Texas and Louisiana. Plants in Illinois, Kentucky, Ohio, West Virginia and New Jersey also utilize significant quantities of natural gas for industrial feedstocks. Figure 7-11 shows natural gas and LPG consumption for industrial feedstocks by region.

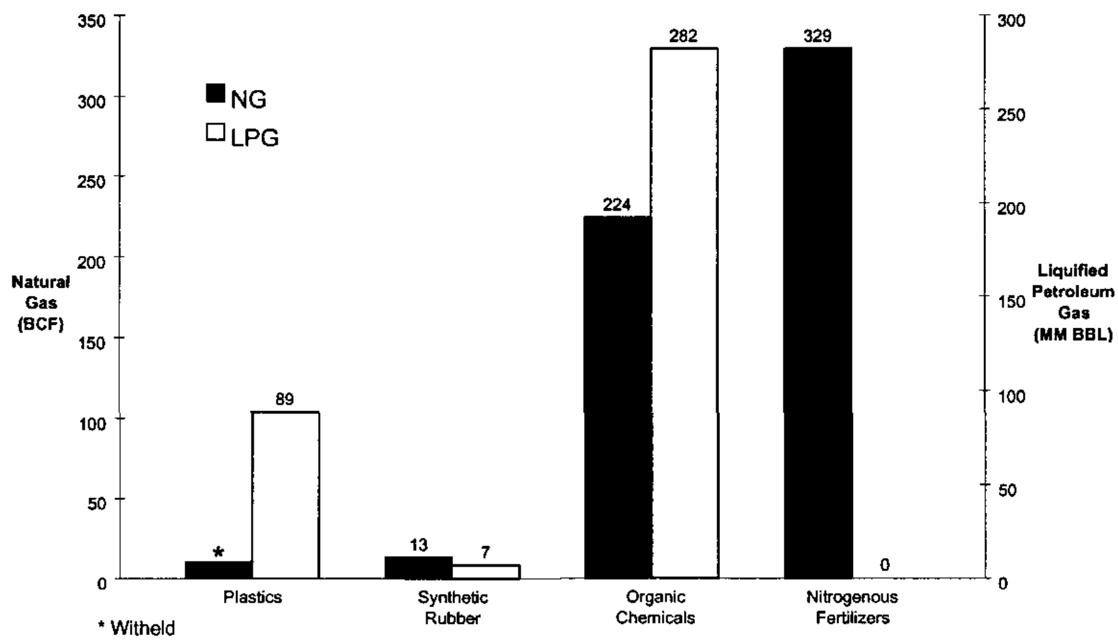
Eighty-six percent of the natural gas and over 87% of the LPG used for industrial feedstocks are utilized in four industries: (1) plastics, (2) synthesis rubber, (3) organic chemicals, and (4) nitrogenous fertilizers. Figure 7-12 depicts the amount of gas consumed by each of these industries.

Each of these industries represents a potential market for syngas. Where the MTCI can produce syngas on a cost-competitive basis, there may be significant market opportunities.

## FIGURE 7-11: NATURAL GAS AND LPG USE AS AN INDUSTRIAL FEEDSTOCK, BY REGION (1994)




## FIGURE 7-12: NATURAL GAS AND LPG USE AS FEEDSTOCK, BY MAJOR INDUSTRIAL CONSUMERS (1994)



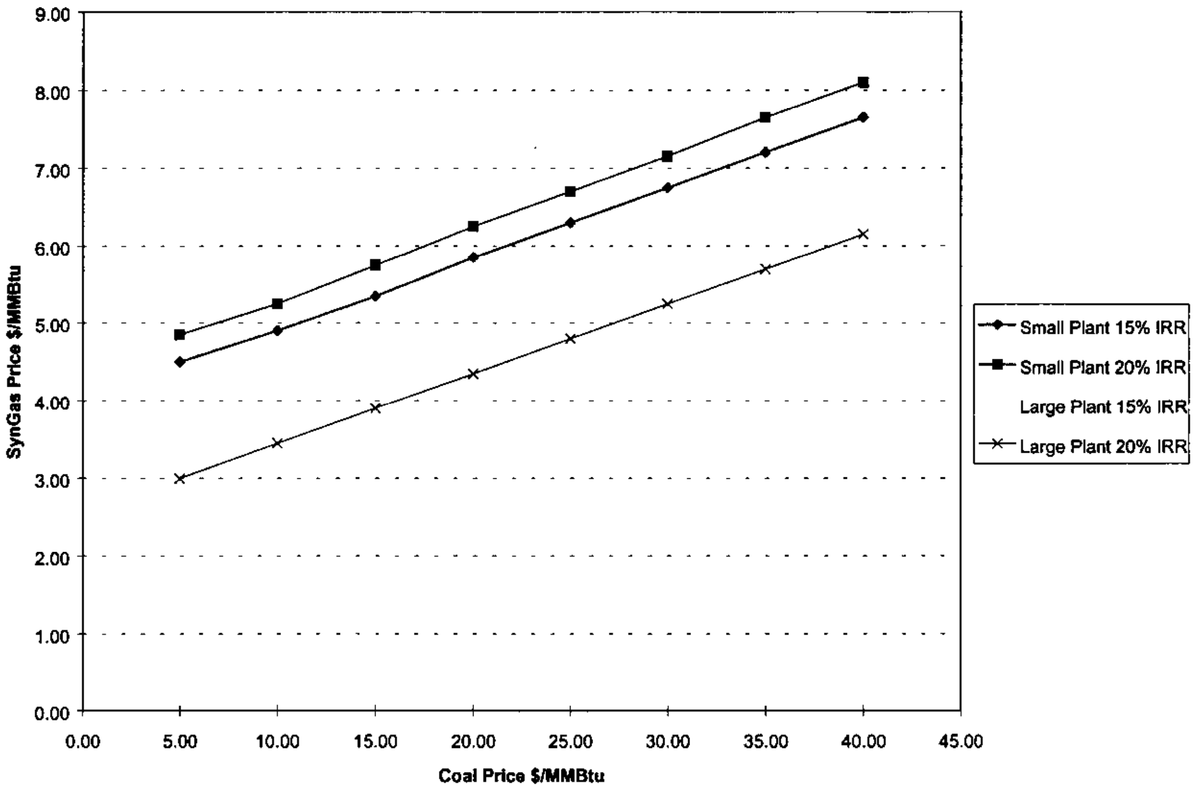

* Witheld

Total Consumption: 566 BCF Natural Gas (84%)
378,000,000 BBL LPG (87%)

### 7.5.2 Preliminary Market Assessment for MTCI

Based upon information obtained from industrial sources, conventional methods for reforming natural gas to synthetic gas are capital intensive. As a result, the cost of synthetic gas derived from natural gas is roughly 1 $^{1}/_{2}$ to 3 times the price of natural gas feedstock. Considering that natural gas supplied to industrial users in the states where most of the synthetic gas users are located is \$3-\$4/MMBtu, the synthetic gas prices for industrial feedstocks are on the order of \$4.50-\$12/MMBtu. Where a commercial-scale MTCI steam reformer can produce a syngas having comparable chemical properties within or less than this price range, there may be market opportunities for the technology. The price of syngas produced by the MTCI technology is dependent upon the cost of coal used as its feedstock. Figure 7-13 shows the relationship between coal price and syngas price for a large MTCI plant and a small plant using both 15% and 20% IRR assumptions. To compete with \$4.50/MMBtu conventional syngas, a large MTCI plant would have to use \$23-\$25/MMBtu coal. A small MTCI plant would have to use \$5/MMBtu coal and a 15% IRR to be competitive with \$4.50 syngas. At the upper end of the conventional syngas cost range, the MTCI technology would be competitive no matter what the coal price or the IRR considered.

**FIGURE 7-13: PRICE OF SYNGAS AS A FUNCTION OF DELIVERED COAL PRICE**



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# EXHIBITS

# for

# FINAL REPORT VOLUME 1
# PUBLIC DESIGN

## EXHIBIT 1

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## EXHIBIT 2: MAJOR EQUIPMENT LIST

| Item No. | Item Name | Quantity | | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | Operating | Spare | | | | |
| 1 | Coal-Handling System: | | | 40 ton/hr (wet) | | | |
| 2 | Bucket Elevator | 1 | | 40 ton/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 3 | Conveyor | 1 | | 40 ton/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 4 | Weigh Feeder | 1 | | 40 ton/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 5 | Feed Screw | 1 | | 40 ton/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 6 | Storage Bin | 1 | | 40 ton/hr | Cylindrical with 70° Cone Bottom | Carbon Steel | Multiple Vendor Quotes |
| 7 | Reactor w/steam distributor | 1 | | 36.1 ton/hr (wet) | Refractory-lined Rectangular Vessel | Carbon Steel | ThermoChem |
| 8 | Pulsed Heater w/Plenum & Aerovalves | 5 | | 253-tube 6.0 MMBtu/hr each | PulseEnhanced™ | 321 SS | ThermoChem |
| 9 | Pulsed Heater Combustion Air Fan | 2 | | 9400 ACFM @ 28" WC | 75 HP Blower | Carbon Steel | ThermoChem |
| 10 | Char-Handling System: | | | 13.5 ton/hr (dry) | | | |
| 11 | Lock Hopper | 1 | | 1,000 lbs. char | Standard | Carbon Steel | ThermoChem |
| 12 | Cooling Conveyor | 1 | | 13.5 ton/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 13 | Char-Slurry Mixing Tank | 1 | | 27 ton | Cylindrical with Conical Bottom | Carbon Steel | Multiple Vendor Quotes |
| 14 | Char-Mixing Tank Pumps | 2 | | 66 Gpm, 7.5 HP each | Slurry-Handling | Carbon Steel | Multiple Vendor Quotes |
| 15 | Char-Mixing Tank Agitator | 1 | | 5 HP each | Medium Turbulence | Carbon Steel | Multiple Vendor Quotes |
| 16 | First Stage Cyclone | 4 | | 5000 ACFM | 95% Removal | 321 SS | ThermoChem |
| 17 | Second Stage Cyclone | 4 | | 5000 ACFM | 99.5% Removal | Refractory-lined Carbon Steel | ThermoChem |

**EXHIBIT 2 (continued): MAJOR EQUIPMENT LIST**

| Item No. | Item Name | Quantity | | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | Operating | Spare | | | | |
| 18 | Heat Recovery Steam Generator # 1 (HRSG1) | 1 | | 26250 lb./hr @ 150 psig | Unfired | Carbon Steel | ThermoChem |
| 19 | HRSG1 Recirculation Pump | 1 | 1 | 60 GPM | 25 HP High Temp/ Pressure Service | Carbon Steel | ThermoChem |
| 20 | Venturi Scrubber | 1 | | 20000 ACFM | S. Steel Throat | Carbon Steel Body | ThermoChem |
| 21 | Venturi Scrubber Pump | 1 | 1 | 160 GPM, 10 HP each | Slurry-Handling | Carbon Steel | ThermoChem |
| 22 | Gas Cooler Column | 1 | | 20000 ACFM | 5.5' D X 19' H Packed | Carbon Steel | ThermoChem |
| 23 | Gas Cooler Tank | 1 | | 5000 | Cylindrical w/Dished Bottom | Carbon Steel | ThermoChem |
| 24 | Gas Cooler Heat Exchanger | 1 | | 2 MM Btu/hr | Plate Heat Exchanger | Carbon Steel | ThermoChem |
| 25 | Gas Cooler Recirculation Pump | 1 | 1 | 760 GPM, 20 HP each | Centrifugal | Carbon Steel | ThermoChem |
| 26 | $H_2S$ Absorber | 1 | | 20000 ACFM | 5.5' D X 24' H Packed | Carbon Steel | ThermoChem |
| 27 | $H_2S$ Absorber Recirculation Pump | 1 | 1 | 110 GPM, 2 HP each | Centrifugal | Carbon Steel | ThermoChem |
| 28 | Superheater | 1 | | 4.2 MM Btu/hr | Standard | 304 St. Steel | ThermoChem |
| 29 | Heat Recovery Steam Generator 2 (HRSG2) | 1 | | 39,000 lb./hr @ 150 psig | Fired with off-gas or Natural gas | Carbon Steel | Multiple Vendor Quotes |
| 30 | Air Heater | 1 | | 9 MM Btu/hr | Standard | Carbon Steel | Multiple Vendor Quotes |
| 31 | Stack | 1 | | 20000 ACFM | 83' H | Carbon Steel | Multiple Vendor Quotes |
| 32 | SS Duct Work | 1 lot | | 6700 Sq. ft. | 3/16" Different Sizes | 304 St. Steel | Multiple Vendor Quotes |
| 33 | Carbon Steel Duct Work | 1 lot | | 3300 Sq. ft. | 3/16" Different Sizes | Carbon Steel | Multiple Vendor Quotes |

## EXHIBIT 3: MAJOR EQUIPMENT COSTS

| Item No. | Item Name | F.O.B. Cost/Unit | Sales Tax | Freight Cost | Installing Cost | Total Cost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Equipment | Freight | On | |
| 1 | Coal-Handling Systems: | | | | | | | | | | |
| 2 | Bucket Elevator | 100,000 | | 2,000 | 5,000 | 107,000 | 1.0 | 100,000 | 2,000 | 5,000 | 107,000 |
| 3 | Conveyor | 155,000 | | 3,100 | 5,000 | 163,100 | 1.0 | 155,000 | 3,100 | 5,000 | 163,100 |
| 4 | Weigh Feeder | 50,000 | | 1,000 | 2,500 | 53,500 | 1.0 | 50,000 | 1,000 | 2,500 | 53,500 |
| 5 | Feed Screw | 75,000 | | 1,500 | 2,500 | 79,000 | 1.0 | 75,000 | 1,500 | 2,500 | 79,000 |
| 6 | Storage Bin | 300,000 | | 6,000 | 12,500 | 318,500 | 1.0 | 300,000 | 6,000 | 12,500 | 318,500 |
| 7 | Reactor w/Steam Distributor | 401,000 | | 8,020 | 110,000 | 519,020 | 1.0 | 401,000 | 8,020 | 110,000 | 519,020 |
| 8 | Pulsed Heater w/ Plenum & Aerovalves | 507,800 | | 10,156 | 10,000 | 527,956 | 5.0 | 2,539,000 | 50,780 | 50,000 | 2,639,780 |
| 9 | Pulsed Heater Combustion Air Fan | 12,500 | | 250 | 6,790 | 19,540 | 2.0 | 25,000 | 500 | 13,580 | 39,080 |
| 10 | Char-Handling System: | | | | | | | | | | |
| 11 | Lock Hopper | 2,000 | | 40 | 1,500 | 3,540 | 1.0 | 2,000 | 40 | 1,500 | 3,540 |

## EXHIBIT 3 (continued): MAJOR EQUIPMENT COSTS

| Item No. | Item Name | F.O.B. Cost/Unit | Sales Tax | Freight Cost | Installing Cost | Total Cost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Equipment | Freight | On | |
| 12 | Cooling Conveyor | 50,000 | | 1,000 | 2,500 | 53,500 | 1.0 | 50,000 | 1,000 | 2,500 | 53,500 |
| 13 | Char-Mixing Tank | 5,000 | | 100 | 950 | 6,050 | 1.0 | 5,000 | 100 | 950 | 6,050 |
| 14 | Char-Mixing Tank Pumps | 2,000 | | 40 | 2,500 | 4,540 | 2.0 | 4,000 | 80 | 5,000 | 9,080 |
| 15 | Char-Mixing Tank Agitator | 2,000 | | 40 | 1,000 | 3,040 | 1.0 | 2,000 | 40 | 1,000 | 3,040 |
| 16 | First Stage Cyclone | 36,250 | | 725 | 2,500 | 39,475 | 4.0 | 145,000 | 2,900 | 10,000 | 157,900 |
| 17 | Second Stage Cyclone | 37,500 | | 750 | 2,500 | 40,750 | 4.0 | 150,000 | 3,000 | 10,000 | 163,000 |
| 18 | Heat Recovery Steam Generator # 1 | 300,000 | | 6,000 | 14,900 | 320,900 | 1.0 | 300,000 | 6,000 | 14,900 | 320,900 |
| 19 | Recirculation Pump | 3,500 | | 70 | 3,100 | 6,670 | 2.0 | 7,000 | 140 | 6,200 | 13,340 |
| 20 | Venturi Scrubber w/Throat | 13,000 | | 260 | 2,300 | 15,560 | 1.0 | 13,000 | 260 | 2,300 | 15,560 |
| 21 | Venturi Scrubber Pump | 4,500 | | 90 | 4,100 | 8,690 | 2.0 | 9,000 | 180 | 8,200 | 17,380 |
| 22 | Gas Cooler Column | 12,000 | | 240 | 2,500 | 14,740 | 1.0 | 12,000 | 240 | 2,500 | 14,740 |

## EXHIBIT 3 (continued): MAJOR EQUIPMENT COSTS

| Item No. | Item Name | F.O.B. Cost/Unit | Sales Tax | Freight Cost | Installing Cost | Total Cost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Equipment | Freight | On | |
| 23 | Gas Cooler Tank | 2,500 | | 50 | 1,000 | 3,550 | 1.0 | 2,500 | 50 | 1,000 | 3,550 |
| 24 | Gas Cooler Heat Exchanger | 4,000 | | 80 | 1,000 | 5,080 | 1.0 | 4,000 | 80 | 1,000 | 5,080 |
| 25 | Gas Cooler Recirculation Pump | 11,000 | | 220 | 3,100 | 14,320 | 2.0 | 22,000 | 440 | 6,200 | 28,640 |
| 26 | $H_2S$ Absorber | 13,000 | | 260 | 2,500 | 15,760 | 1.0 | 13,000 | 260 | 2,500 | 15,760 |
| 27 | $H_2S$ Absorber Recirculation Pump | 2,500 | | 50 | 3,100 | 5,650 | 2.0 | 5,000 | 100 | 6,200 | 11,300 |
| 28 | Superheater | 35,000 | | 700 | 1,500 | 37,200 | 1.0 | 35,000 | 700 | 1,500 | 37,200 |
| 29 | Heat Recovery Steam Generator 2 | 708,000 | | 14,160 | 24,800 | 746,960 | 1.0 | 708,000 | 14,160 | 24,800 | 746,960 |
| 30 | Air Heater | 150,000 | | 3,000 | 2,500 | 155,500 | 1.0 | 150,000 | 3,000 | 2,500 | 155,500 |
| 31 | Stack | 25,000 | | 500 | 2,500 | 28,000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| 32 | St. Steel Duct Work (one lot) | | | | 188,000 | 188,000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| 33 | C. Steel Duct Work (one lot) | | | | 188,00 | 188,000 | 1.0 | 0 | 0 | 188,000 | 188,000 |
| 34 | Equipment Paint (one lot) | | | | 21,000 | 21,000 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| 35 | Insulation Including Duct (one lot) | | | | 81,000 | 81,000 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| 36 | Miscellaneous Materials | | | | 209,000 | 209,000 | 1.0 | 0 | 0 | 209,000 | 209,000 |
| | **Major Equipment Cost Totals** | | | | | | | **5,333,500** | **106,670** | **755,830** | **6,196,000** |

**EXHIBIT 4**

**SUMMARY OF ESTIMATED OPERATING COSTS**

(Refer to Table 6-2 for further details)

| **ANNUAL FIXED OPERATING COST** | | |
|---|---|---|
| Operating Labor Cost Details | | |
| Number of Operators per Shift | 6.67 | |
| Number of Shifts per Week | 4.2 | |
| Operating Pay Rate per Hour | $15.53 | |
| 1. Total Annual Operating Labor Cost | | $952,300 |
| 2. Total Annual Maintenance Labor Cost | | $272,000 |
| 3. Total Annual Maintenance Material Cost | | $665,000 |
| 4. Total Annual Administrative and Support Labor Cost | | $158,000 |
| 5. Total Annual Overhead Cost | | $500,000 |
| 6. Total Annual G&A Cost | | $433,000 |
| **7. TOTAL ANNUAL FIXED O&M COST** | | **$2,980,300** |
| | | |

**VARIABLE OPERATING COST**

| **Commodity*** | **Unit** | **$/Unit** | **Quantity/Hr** | **Cost $/hr** |
|---|---|---|---|---|
| Coal Feedstock | Dry ton | 5.96 | 36.1 | 215.16 |
| Electricity | KW/H | 0.05 | 1805 | 90.25 |
| Other Variable Expenses | Dry ton | 1.64 | 36.1 | 59.20 |
| By-Product Gas Revenue | MMBtu | 5.00 | 284.5 | ($1,423) |
| **TOTAL VARIABLE OPERATING COST** | | | | **($1,058)** |

* Includes process fuels, sorbents, chemicals, water, auxiliary power, and waste disposal.

## EXHIBIT 5

## SUMMARY OF ESTIMATED STARTUP COSTS

(Refer to Table 6-1 for further details)

| Start-Up Cost Element | Cost, $ |
|---|---|
| Operating Labor Cost | 476,000 |
| Maintenance and Materials Cost | 170,000 |
| Administrative and Support Cost | 546,000 |
| Commodity Cost: | |
| 1. Coal Feedstock | 390,000 |
| 2. Electricity | 330,000 |
| 3. Initial Startup Fuel | 61,000 |
| 4. Other Commodities* | 108,000 |
| **TOTAL INITIAL START-UP COSTS** | **$2,081,000** |

* Includes process fuels, sorbents, chemicals, water, auxiliary power, and waste disposal

# FINAL REPORT

# VOLUME 2: PROJECT PERFORMANCE AND ECONOMICS

# PULSE COMBUSTOR DESIGN QUALIFICATION TEST AND CLEAN COAL FEEDSTOCK TEST

**PREPARED FOR:**

**U.S. Department of Energy**
**National Energy Technology Laboratory**
**(Under Cooperative Agreement No. DE-FC22-92PC92644)**

**PREPARED BY:**

**ThermoChem, Inc.**
**6001 Chemical Road**
**Baltimore, Maryland 21226**

**Draft Report Issued on: February 18, 2002**

**Final Report Issued on: March 29, 2002**

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## FORWARD

This work was performed under Cooperative Agreement No. DE-FC22-92PC92644 between the United States Department of Energy ('DOE) and ThermoChem, Inc (TCI). The work was carried out by (TCI) at its development testing and manufacturing facilities located at 6001 Chemical Road, Baltimore, Maryland 21226. Participants associated with this project are given below:


ThermoChem, Inc.

Project Manager/Chief Engineer – W. G. Steedman
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 43
Fax: (410) 354-9894
E-mail: wsteedman@tchem.net

ThermoChem Business Official

Vice President – L. Rockvam
ThermoChem, Inc.
6001 Chemical Road
Baltimore, Maryland 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

U.S. Department of Energy

Project Manager – Leo E. Makovsky
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, Pennsylvania 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

## ABSTRACT

For this Cooperative Agreement, the pulse heater module is the technology envelope for an indirectly heated steam reformer. The field of use of the steam reformer pursuant to this Cooperative Agreement with DOE is for the processing of sub-bituminous coals and lignite. The main focus is the mild gasification of such coals for the generation of both fuel gas and char for the steel industry. An alternate market application is also presented for the substitution of metallurgical coke.

This project was devoted to qualification of a scaled-up 253-tube pulse heater module. This module was designed, fabricated, installed, instrumented and tested in a fluidized bed test facility. Several test campaigns were conducted. This larger heater is a 3.5 times scale-up of the previous pulse heaters containing 72 tubes each. The smaller heater was part of previous pilot field test of the steam reformer at Weyerhaeuser's pulp mill in New Bern, North Carolina.

The project also included collection and reduction of mild gasification process data from operation of the process development unit (PDU) in Baltimore. The operation of the PDU was aimed at conditions required to produce char (and gas) for the Northshore Mining in Silver Bay, Minnesota. Northshore supplied the coal for the process unit tests.

## ACKNOWLEDGEMENTS

TCI wishes to acknowledge the contributions of the DOE Project Managers on this project namely, Mr. William Mundorf, Mr. Art Baldwin, the late Mr. Steve Heinz, Mr. Bob Kornosky, Mr. Mike Eastman, Mr. Doug Gyorke, Dr. Tom Sarkas, Mr. Gary Stats and Mr. Leo Makovsky. TCI also wishes to acknowledge the contribution of our cost sharing partners during the course of this project, namely Mr. Denny Hunter of the Weyerhaeuser Paper Company, Mr. Lance Ahearn of the Heartland Development Corporation, and Mr. Frank Tenore of ThermoChem Recovery International (TRI). Furthermore, TCI also acknowledges the contributions of Mr. Jack Siegel of Energy Resources International, Mr. Dan Burciaga of Industra and the support by Javan and Walters Engineering Group.

# POINT OF CONTACT

ThermoChem, Inc.

Leland (Lee) Rockvam
Vice President
ThermoChem, Inc.
6001 Chemical Road
Baltimore, MD 21226
Telephone: (410) 354-9890 ext. 41
Fax: (410) 354-9894
E-mail: lrockvam@tchem.net

DOE

Leo E. Makovsky
Project Manager
U.S. Department of Energy, NETL
626 Cochrans Mill Road, P.O. Box 10940
Pittsburgh, PA 15236-0940
Telephone: (412) 386-5814
Fax: (412) 386-4775
E-mail: leo.makovsky@netl.doe.gov

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## LIST OF ABBREVIATIONS

| | | |
|---|---|---|
| ASME | --- | The American Society of Mechanical Engineers |
| BMCS | --- | Burner Management Control System |
| BMS | --- | Burner Management System |
| BOD | --- | Biological Oxygen Demand |
| CCT | --- | Clean Coal Technology |
| COD | --- | Chemical Oxygen Demand |
| DOE | --- | Department of Energy |
| DRI | --- | Direct Reduction of Iron |
| EIA | --- | Environmental Impact Assessment |
| EPA | --- | Environmental Protection Agency |
| EPC | --- | Engineering Procurement Construction |
| FFT | --- | Fast Fourier Transform |
| FGD | --- | Flue Gas Desulfurization |
| FGR | --- | Flue Gas Recirculation |
| FR | --- | Firing Rate |
| G&A | --- | General and Administration |
| GC | --- | Gas Chromatograph |
| GHG | --- | Greenhouse Gas |
| GRI | --- | Gas Research Institute |
| HRSG | --- | Heat Recovery Steam Generator |
| IRR | --- | Internal Rate of Return |
| LPG | --- | Liquefied Petroleum Gas |
| MCC | --- | Motor Control Center |
| MTCI | --- | Manufacturing and Technology Conversion International, Inc. |
| NERC | --- | National Electric Reliability Council |
| NGCC | --- | Natural Gas Combined Cycle |
| NPCC | --- | New England |
| PC | --- | Pulse Combustor |
| PDU | --- | Process Development Unit |
| PFD | --- | Process Flow Diagram |
| P&ID | --- | Piping & Instrumentation Diagrams |
| PLC | --- | Programmable Logic Controller |
| O&M | --- | Operation & Maintenance |
| R | --- | Reactor |

## LIST OF ABBREVIATIONS (Continued)

| | | |
|---|---|---|
| RDF | --- | Refuse Derived Fuel |
| RO | --- | Reverse Osmosis |
| ROI | --- | Return On Investment |
| SCR | --- | Selective Catalytic Reduction |
| SNCR | | Selective Non-Catalytic Reduction |
| SS | --- | Stainless Steel |
| SVOC | --- | Semi-Volatile Organic Compounds |
| TC | --- | Thermocouple |
| TCI | --- | ThermoChem, Inc. |
| THC | --- | Total Hydrocarbons |
| TRI | --- | ThermoChem Recovery International, Inc. |
| VOC | --- | Volatile Organic Compounds |

## LIST OF UNITS

| | | |
|---|---|---|
| acfm | --- | Actual Cubic Feet per Minute |
| Btu | --- | British Thermal Unit |
| C | --- | Degrees Celsius |
| dia. | --- | Diameter |
| F | --- | Degrees Fahrenheit |
| ft | --- | Feet |
| gal | --- | Gallon |
| gpm | --- | Gallons Per Minute |
| GW | --- | Gigawatts |
| hp | --- | Horsepower |
| h | --- | Hour |
| Hz | --- | Hertz |
| kW | --- | Kilowatt |
| kWh | --- | Kilowatt-hour |
| lb | --- | Pound |
| MM | --- | Million |
| MW | --- | Megawatt |
| ppm | --- | Pounds per Minute |
| psig | --- | Pounds per Square Inch |
| scfm | --- | Square Cubic Feet per Minute |
| sq. ft. | --- | Square feet |

## GLOSSARY OF TERMS

C: Carbon

CO: Carbon Monoxide

$CO_2$: Carbon Dioxide

Coke: Coke is made by baking a blend of selected Bituminous coals (called Coking coal or Metallurgical Coal) in special high temperature ovens without contact with air until almost *all of the volatile matter is driven off. Metallurgical coke provides the carbon and heat* required to chemically reduce iron ore to molten pig iron (hot metal). For coke to have the proper physical properties to perform this function, it must be carbonized at temperatures between 900 and 1095°C. The most important physical property of metallurgical coke is its strength to withstand breakage and abrasion during handling and its use in the blast furnace. The most common process currently used to manufacture metallurgical coke is the by-product process.

$H_2S$: Hydrogen Sulfide

$NO_X$: Nitrogen Oxides

NaHS: Sodium Hydrasulfide

$O_2$: Oxygen

S: Sulfur

$SO_2$: Sulfur dioxide

THC: Total Hydrocarbons

## EXECUTIVE SUMMARY


Brief Description of the Project

TCI and its affiliate, MTCI, have developed the PulseEnhanced™ Steam Reforming Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled-up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications. TCI and its subsidiary, TRI, are the project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project and has title to all equipment purchased or fabricated under the project.

The project includes two areas of emphasis:

(i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and,

(ii) process characterization through coal feedstock tests in a Process Development Unit (PDU).

The 61- and 72- tube heater bundles, which were previously demonstrated, are too small in capacity for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require the larger 253-tube heater bundles. For example, a 7-heater (253-tube) reformer can mild gasify over 1,100 short tons of coal per day. If the smaller 72-tube heater modules were used, the reformer would require 25 such units, each with its own fuel train, combustion air and flue gas connections.

Project History

On October 27, 1992, the DOE and TCI entered into a Cooperative Agreement for a Demonstration project under the Clean Coal IV solicitation. Preliminary design and engineering work was conducted for a series of potential sites for a demonstration facility, and a scaled-up 253-tube pulse heater bundle was designed and fabricated. On

September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

## Technology Being Employed

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost. The project has qualified the design of the 253-resonance tube pulse heater, which is the technology envelope and the heart of a commercial-scale system.

## Project Location

The project is located at TCI's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor installation within the Company premises, and the PDU is located indoors in the Company's Development and Manufacturing plant.

## Summary of Test Program

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields and composition, char yields and composition and endothermic heat requirements were determined in the PDU Test Facility.

## Project Costs

The total cost of this project was $8.6 million, with DOE providing fifty percent of this cost.

Based on the test data, it is projected that a commercial-scale facility capable of processing 40 US tons per hour in a mild gasification mode will have an installed capital cost of $28,184,000.

# 1.0 PROJECT OVERVIEW

## 1.1 Purpose of the Project Performance and Economics Report

The purpose of the Project Performance and Economics Report is to consolidate, for the purpose of public use, all performance information on the project at the completion of the project. The report provides an overview of the project, the salient performance features and data, and the role of the pulse combustor design qualification test project in commercialization planning.

## 1.2 Overview of the Project

*TCI and its affiliate, MTCI, have developed the PulseEnhanced™ Steam-Reforming* Technology for gasification of coal and other organic feedstocks. The goal of this project is to demonstrate a scaled up pulsed heater, which is the heart of a commercial-scale steam reformer system for coal gasification and other significant commercial applications.

The project includes two areas of emphasis:

(i) the demonstration of a scaled-up 253-tube pulsed heater bundle as an essential step in commercialization of the technology and,

(ii) process characterization through coal feedstock tests in a PDU.

The 61- and 72-tube heater bundles, which were previously demonstrated, are too small for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units and the vast majority of commercial black liquor recovery, municipal solid waste and biomass cogeneration units employing the technology will require the larger 253-tube heater bundles.

### 1.2.1 Background and History of Project

On October 27, 1992, DOE and TCI entered into a Cooperative Agreement for a Demonstration project under the Clean Coal IV solicitation. Preliminary design and engineering work was conducted for a series of potential sites for a demonstration facility, and a scaled-up 253-tube pulse heater bundle was designed and fabricated. On

September 29, 1998, the project was revised to provide for a Pulse Combustor Design Qualification Test with a reduced scope and cost.

### 1.2.2 Project Organization

TCI and its subsidiary, TRI, are the revised project sponsors. TRI is responsible for providing all private sector funding for cost sharing the project and has title to all equipment purchased or fabricated under the project.

### 1.2.3 Project Description

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas and if needed, char, without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor. The high heat transfer coefficients exhibited by the MTCI multiple resonance tube pulse combustor permit use of this approach for minimizing the amount of required heat transfer surface. This results in higher throughput and/or lower capital equipment cost.

The project will qualify the design of the 253-resonant tube pulse heater, which is the technology envelope and the heart of a commercial-scale system.

### 1.2.4 Site

The project is located at TCI's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor area within the Company premises, and the PDU is located indoors in the Company Development and Manufacturing plant (see Figure 1-1 on page 1-3).

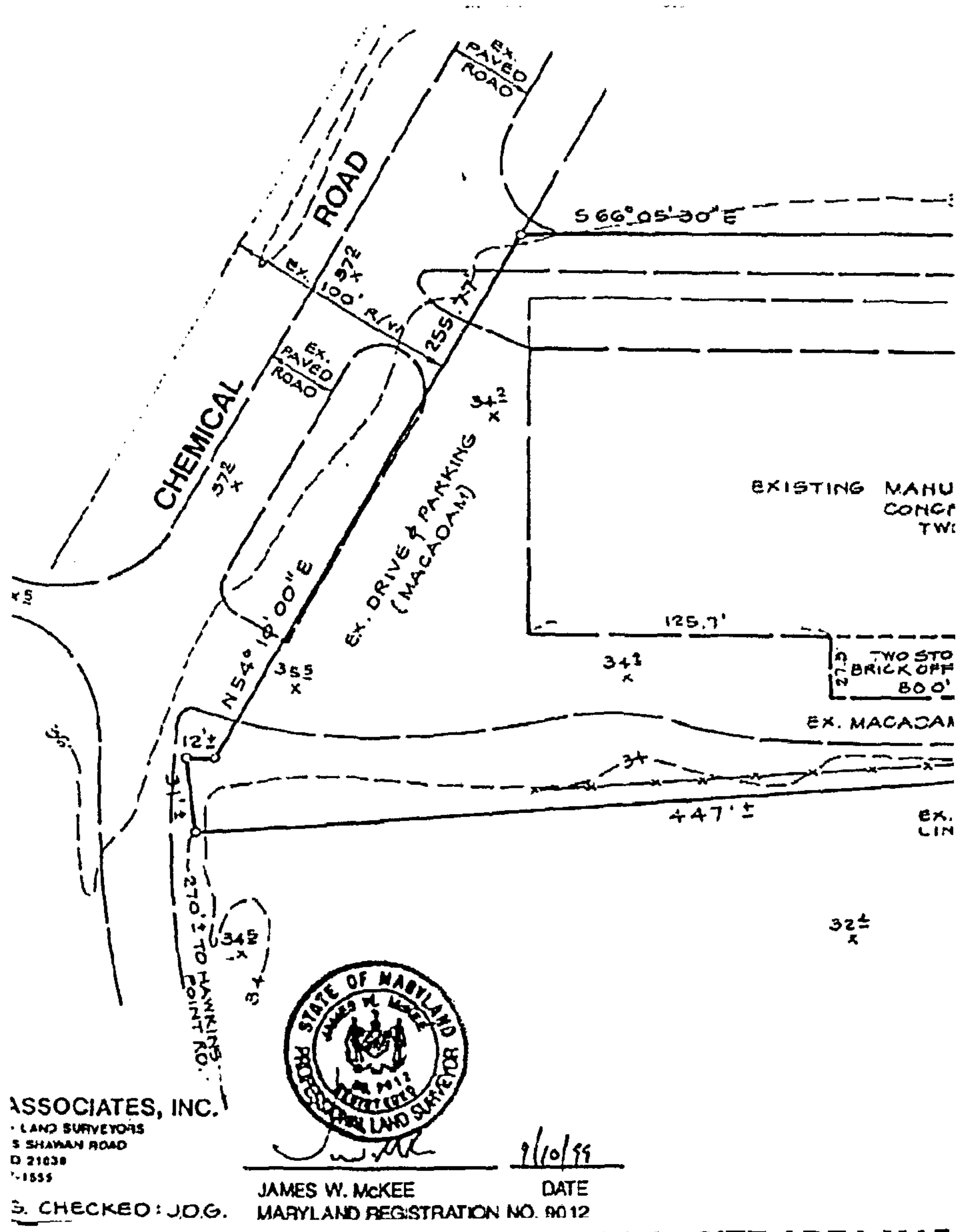
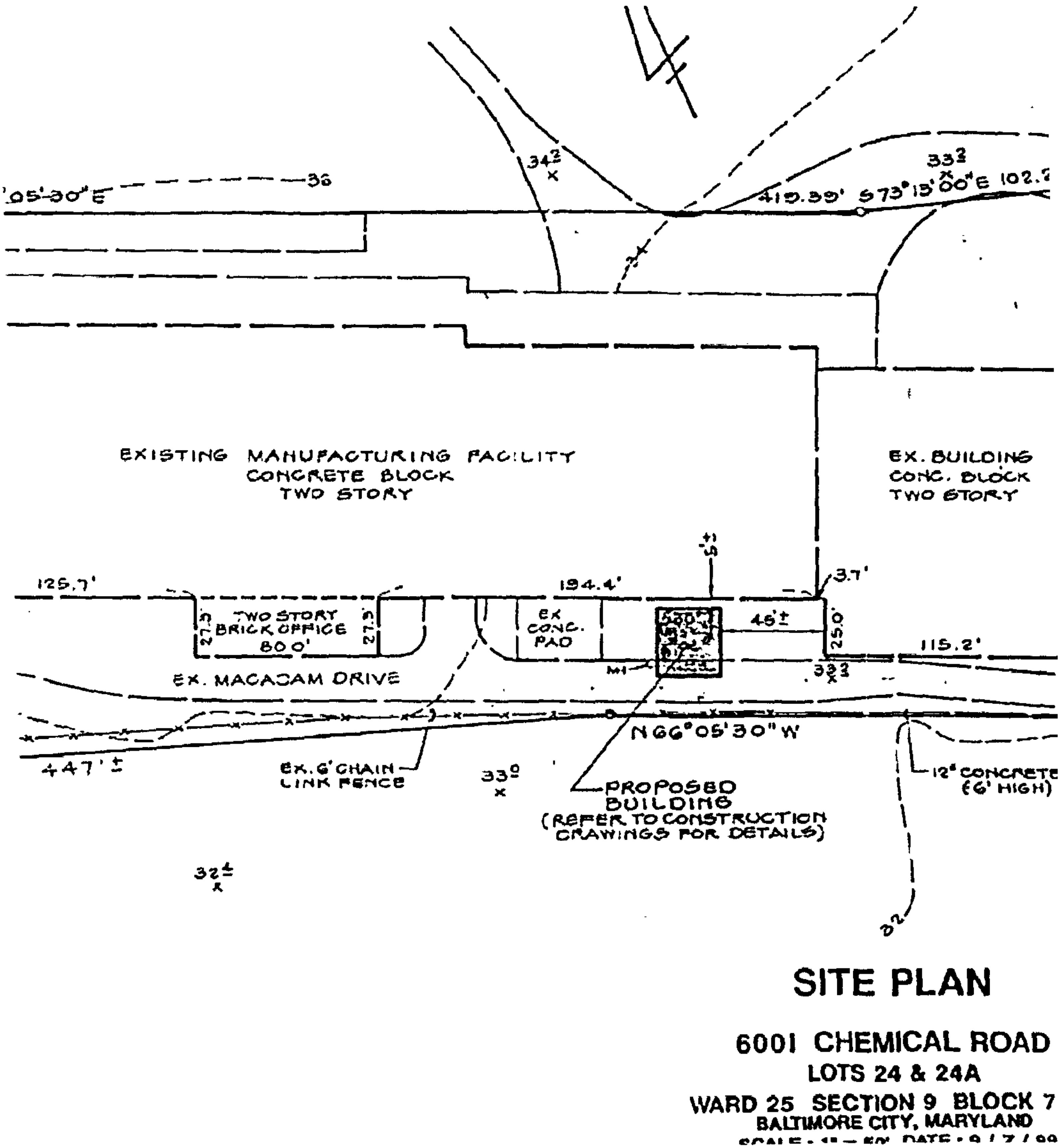



**FIGURE 1-1: SITE AREA MAP**




**: SITE AREA MAP** (Note: Drawing is reproduction and may not be to scale.)

### 1.2.5 Project Schedule

Shakedown and qualification testing of the scaled-up combustor was conducted from October, 2000 through early June 2001. The coal testing in the PDU was conducted in April, 2001.

## 1.3 Objectives of the Project

The purpose of the revised project is to qualify the design of a scaled-up 253-tube pulse heater as an essential step for the commercialization of this technology. The 61- or 72-tube heater bundles, as previously used, are too small in capacity for commercial coal gasification projects and other significant commercial applications. All commercial coal gasification units employing the technology will require the larger 253-tube heater bundles.

### 1.3.1 Qualification Test Objectives

The principal objectives of this program are to perform design qualification testing of a 253-tube pulse heater and to demonstrate its ability to operate in the pulse combustion mode for commercial deployment. The specific objectives include verification and demonstration of:

- Full-scale pulse heater performance and operability; and
- Emissions ($NO_X$, THC, CO) determination.

### 1.3.2 PDU Test Objectives

The objectives of the PDU test will be to evaluate the operability and performance of the system. Specifically, the targets will be:

- Safe, stable and reliable operation,
- Material balance analysis,
- Energy balance analysis,
- Heat of reaction determination,
- Char production and composition determination,

- Product gas composition and yield,
- Bed solids characterization, and
- Cyclone catch solids characterization.

The process data generated from the test will be used for preliminary system design for the full-scale commercial plant.

### 1.4 Significance of the Project

The design qualification of the 253-tube heater bundle will enable TCI to establish the design parameters of the scaled-up heater in order to meet the requirements of the overall system performance for commercial use. Process fluid mechanics, heat transfer, mass transfer and mixing must be preserved in the scale-up to achieve good system performance. For example, the combustion chamber aspect ratio (height-to-diameter) decreases with an increase in pulse heater module size due to acoustic and geometric considerations. This reduced aspect ratio could affect lateral mixing of the fuel and air, temperature uniformity in the resonance tubes, and proper mass flow distribution of the flue gas across the resonance tube-sheet. In addition, the scaled-up heater must be designed to achieve heat addition that is substantially in phase with pressure oscillations. Appropriate controls and instrumentation must also be used to demonstrate the efficacy of the technology in full-scale commercial applications to TCI's EPC partners and bonding/insurance companies.

Qualifying the design of the 253-tube pulse combustor is an enabling measure for the commercial introduction of the MTCI technology in a wide spectrum of end use applications. The MTCI steam-reforming technology is unique with regards to the wide spectrum of feedstocks it can process.

In the area of coal applications, the MTCI steam reformer has the following end use application opportunities:

- Complete steam reforming of sub-bituminous coal and lignite at the mine mouth and producing power with combined cycle gas turbines and Fuel Cells.

In fact, the MTCI technology is the most suitable technology today for the production of reformate gas from coal and waste (combined) in the world.

- Mild gasification of coal for production of char, tars and fuel gas for the U.S. steel industry. In the case of Northshore Mining, the char is used for a DRI process. The tar would be sold to a company the makes asphalt, and the exported gas would be used for taconite processing.

In addition, the MTCI steam reformer technology can process a wide spectrum of coal and wastes (RDF, chicken waste, sewage sludge, hog waste, biomass waste and essentially any liquid or solid material that contains carbon or hydrocarbons (i.e. tires, plastics, etc.).

The target is to use sub-bituminous and lignite coals that are underutilized and also have highly reactive char and wastes to produce clean power and/or other products (ethanol, methanol, acetic acid, etc.).

*This is very significant application and would be enabled by the qualification of the pulse* combustor (the technology envelope) scale-up design qualification.

The MTCI technology is unique in the broad spectrum of its end use applications. In other applications, the MTCI process is the leading technology for processing biomass based feedstocks (black liquor, bark, pistachio nut shells [with 4% sulfur], toxic wastes from industrial sources and low level as well as low level mixed wastes).

## 1.5 Management and DOE's Role in the Project

### 1.5.1 Department of Energy

DOE provided 50% of the funds for this project and monitored project progress and results.

### 1.5.2 Project Management and Execution

TCI Project Manager is responsible for project execution and cost/schedule monitoring and control. The Project Manager was also responsible for supervising the project team including consultants and subcontractors.

### 1.5.3 Project Organization Chart

As depicted by Figure 1-2, the project organization chart, the TCI project manager, Mr. Lee Rockvam, is the interface with the DOE project manager.

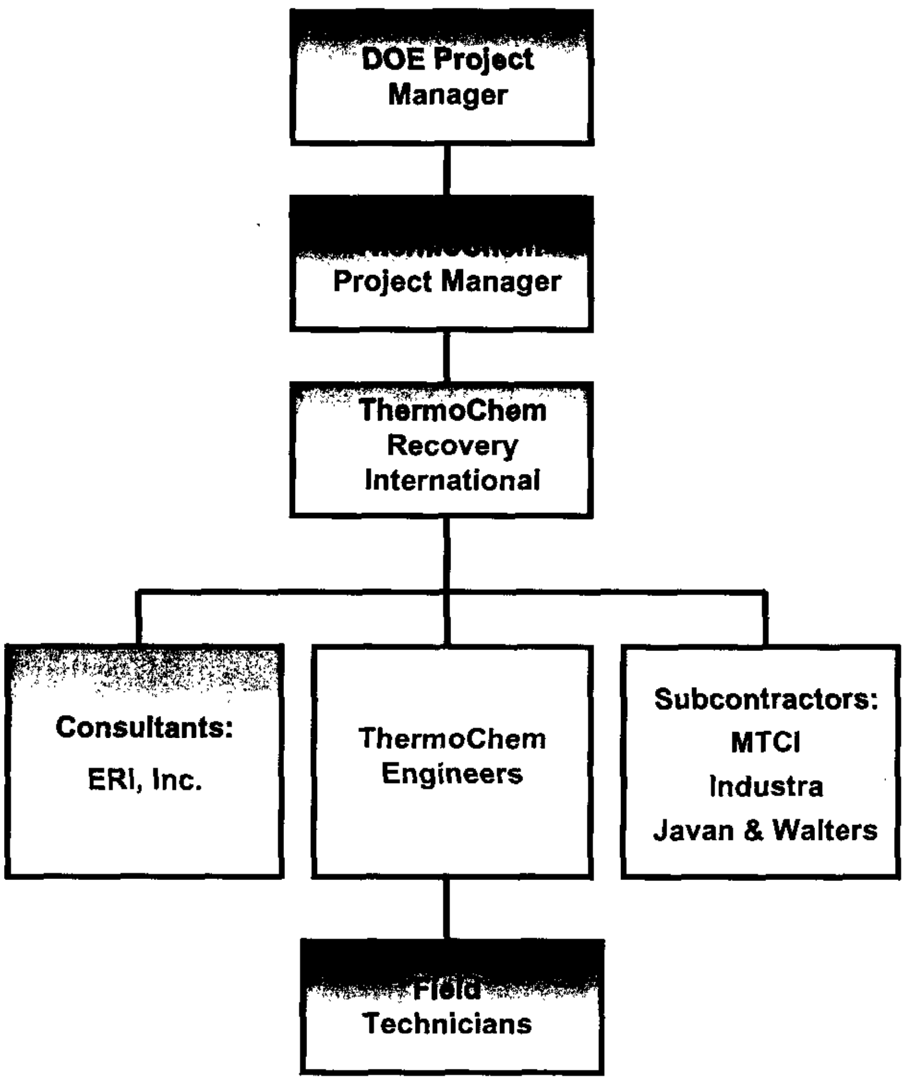



**FIGURE 1-2: ORGANIZATION CHART**

TRI is the private sector cost sharing entity on this project for the Pulse Combustor Design qualification test and the process investigations conducted using the PDU.

The technical project team is comprised of TCI engineers, MTCI engineers, engineers from Industra and Javan & Walters. In addition, MTCI supplied fabrication and site erection personnel as part of the team.

MTCI also augmented the TCI Engineers with test operation personnel. Temporary Field Technicians were also employed on as needed basis to support electrical, welding and test operation activities.

# 2.0 TECHNOLOGY DESCRIPTION

## 2.1 Description of the Demonstrated Technology

The MTCI fluidized bed steam reformer incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by the MTCI multiple resonance tube pulse combustor technology with resonance tubes comprising the heat exchanger immersed in the fluidized bed reactor.

In the TCI steam-reforming system, the multiple resonance tube pulse combustor is employed in which the resonance tubes serve as the heat exchanger to deliver heat indirectly to the fluid bed reactor. At any significant firing rate, a single resonance tube will not have sufficient surface area to transfer all the heat necessary to the fluid bed. Therefore, multiple parallel resonance tubes must be employed. In scaling up the multiple resonance tube pulse combustors, the number of the parallel resonance tubes is increased,, and the ratio of the combustion chamber depth to its diameter is reduced. It is essential that the oscillatory component of the flow velocity in all the resonance tubes be in phase to achieve strong pulsations and, thus, enhanced heat transfer and heat release rates.

The larger the number of tubes, the more critical is the tuning of these self-induced, combustion-driven oscillations. Therefore, a number of independent aerodynamics valves are employed to introduce the combustion air to various segments of the combustion chamber. When tuning a multiple resonance tube pulse combustion system, it is necessary to achieve high pulsation amplitudes in order to ensure a more even distribution of the hot flue gases between the resonance tubes. Such distribution is critical given the high-temperature range required for the heat duty to which the resonance tubes are subjected.

## 2.2 Description of the Demonstrated Facilities

### 2.2.1 Combustor Design Qualification Test Facility

The full scale test facility consists of the following equipment:

- Reformer Vessel

  The reformer consists of a one-inch thick carbon steel plate, reinforced in a rectangular vessel configuration. The vessel is insulated with thermal board and overlaid with 1/16-inch stainless liner.

- Pulse Combustor

  The combustor consists of a 253-tube bundle complete with refractory-lined combustion chamber, aerovalve plate assembly, inlet air plenum and exhaust expansion bellows.

- Fuel train and Burner Management System

  The fuel train consists of a natural gas pressure reducing station, double block and bleed, modulating control valve and orifice metering station.

- Combustion Air System

  The combustion air system includes 5 forced draft fans, damper control and flow measurement pitot tube.

- PC Cooling Water Circuit

  The pulse combustor cooling water circuit consists of a steam drum, recirculation pump, balancing valving and feedwater makeup.

- Cyclone

  The cyclone is a single stage unit complete with dipleg isolation valve and catch drum.

- Water injection system

  The water injection system is supplied with plant water and consists of eight injection nozzles that enter the reformer through the floor of the vessel. Water flow is controlled by a modulating control valve. Purge air prevents pluggage of the injection system in the event that the water is turned off.

- Flue Gas Recycle

  Flue gas recycle is an induced system that consists of ductwork connected to the stack, complete with control damper and flow measurement pitot tube. Recycle flue gas renters the process through he suction of the forced draft combustion air fans.
- Flue Gas Quench

  The hot combustor flue exhaust is quenched by a water injection system prior to entering the stack. High pressure water with air assist is injected into the stack prior to the muffler.
- Controls System

  A dedicated control room complete with a Allen Bradley PLC, PC computers and WinTelligent™ operating software provides control of the Test Facility.

### 2.2.2 PDU Test Facility

The PDU facility has a nominal feedstock capacity of 30 to 50 pounds per hour. Coal will be fed to the reformer reactor by a metering and injection screw system. Fluid bed temperatures are maintained at the desired levels by regulating the pulse combustor firing rate. At these temperatures, the feedstock undergoes high rates of heating, pyrolysis and steam reformation. In the absence of free oxygen, the steam reacts endothermically with the feedstock to produce a medium-Btu syngas rich in hydrogen.

The bed temperature is the variable that is controlled to maximize char production. As the bed temperature is lowered, the carbon/steam reaction rate slows and more char is produced. On the other hand, a reasonably high temperature is needed to reduce the sulfur content of the char and to produce lighter condensable hydrocarbons.

A description of the PDU components and subsystems is provided below. The PDU consists of the following subsystems:

- The steam reformer reactor and two-stage cyclone subsystem,
- Coal metering and injection subsystem,
- Steam boiler and feedwater reverse osmosis (RO) unit,

- Two stages of steam superheater,
- Gas chromatograph (GC) dry gas sampling and measurement,
- Instrumentation and controls.

An overall view of the steam reformer, the two stage cyclone, the second stage cyclone catch pot and the coal metering and injection subsystem is provided in Figure 2-1.

The bed area of the PDU reformer is an 8-inch diameter stainless steel vessel. Fluid bed height is approximately 6 feet. The pulse combustor resonance tubes are installed vertically through the bottom of the reformer vessel in a "U" shape. The resonance tubes are made of 1-½ inch pipe approximately 10 feet in length, identical to those used in the full-scale combustor. Since the resonance tubes are installed in a "U" shape, they occupy only five feet of the bed height.

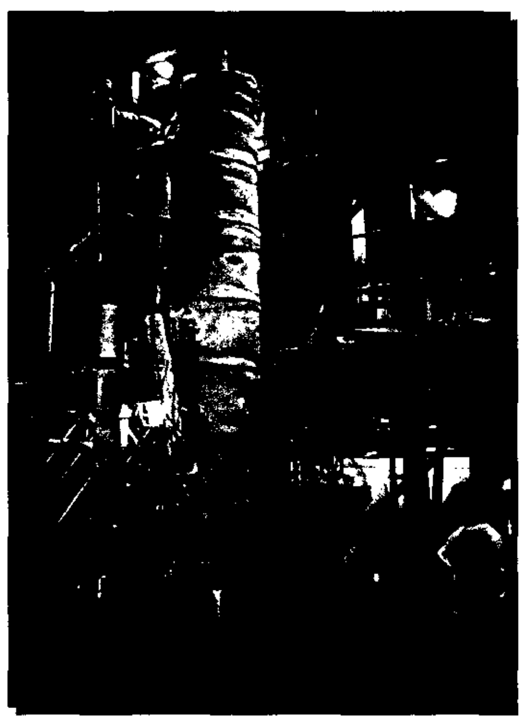


**FIGURE 2-1: PDU TEST FACILITY**

The reformer operates slightly above atmospheric pressure. The startup fluid bed material consists of silica sand and is fluidized with low pressure (15 psig or 1 bar) superheated nitrogen. The reformer operates in the "bubbling" regime with a low superficial velocity of 0.5 to 1.0 foot per second. The low velocity ensures sufficient gas residence time. The two-tube pulsed heater supplies indirect heat for the steam reforming reactions.

A close-up view of the metering and feed system is provided in Figure 4-10. Coal is loaded into the bin at the top. A lockhopper is required because of the pressure differential between the fluid bed reactor and the metering bin. The feed rate control box is also shown in Figure 2-2. The lockhopper utilizes a Dezurik brand knife gate valve and a hemispherical valve to provide a seal between the feed hopper and the

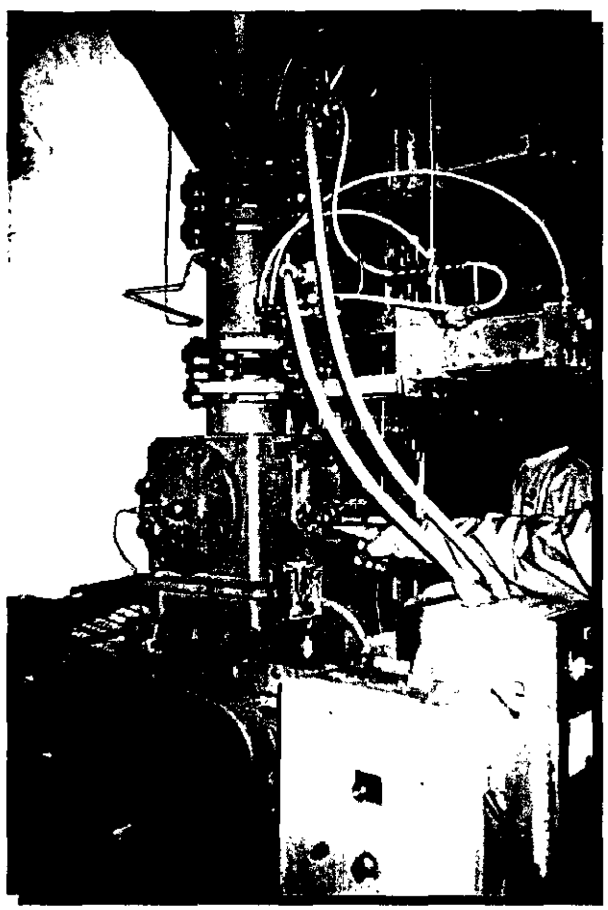


**FIGURE 2-2: COAL METERING AND INJECTION**

metering cavity. Three variable speed, parallel-drive metering screws provide volumetric flow control of the feedstock to the injection screw. The injection screw is operated at a constant speed and transfers the feed to the bottom section of the reformer vessel. The feed injection point is located near the bottom to increase product gas residence time in the bed.

As shown in Figure 2-3, the two-tube pulse combustor has one aerovalve that is supplied with combustion air from the air plenum.

To achieve sufficient oscillations at part load, the natural gas has provisions for air dilution.

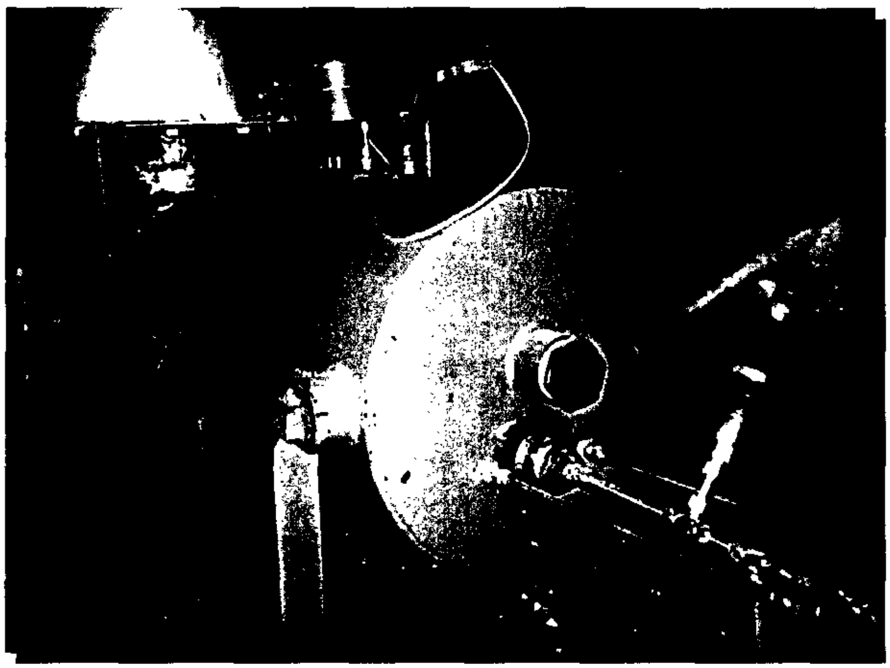


**FIGURE 2-3: PULSE COMBUSTOR COMBUSTION AIR PLENUM**

A close up view of the second stage cyclone catch pot is provided in Figure 2-4.

**FIGURE 2-4: SECOND CYCLONE CATCH POT**

A thermostatically controlled heating shell is provided to avoid steam condensation and refluxing near the end of the cyclone dip leg. A valve allows isolation of the pot for removal. A hydraulic table arrangement is used for moving the pot when disconnected from the dip leg allowing the catch to be sampled and weighed.

Figure 2-5 shows the boiler, which generates the steam used by the steam reformer, and the RO unit and storage tank for feedwater treatment.

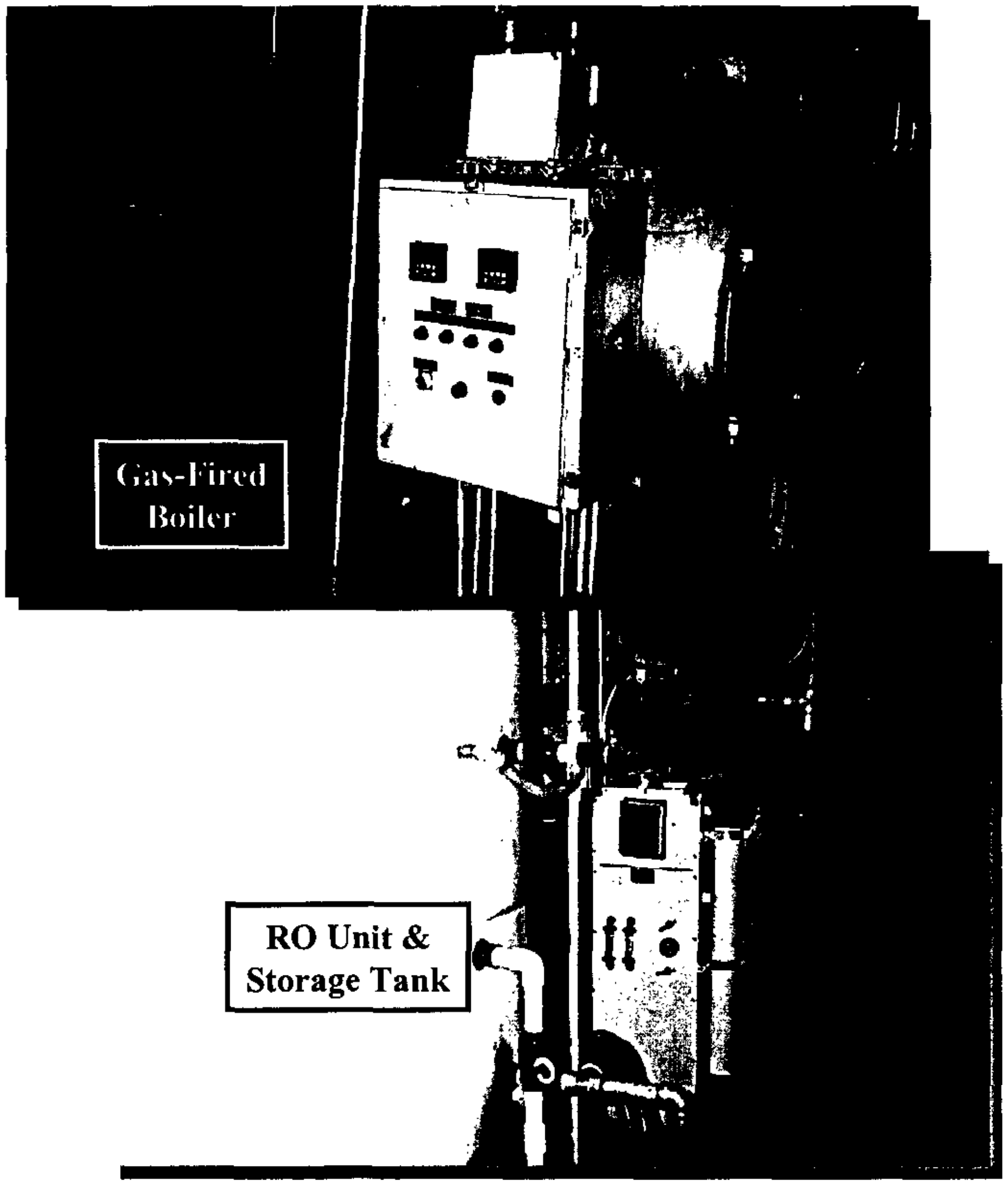



**FIGURE 2-5: STEAM BOILER AND FEEDWATER RO UNIT**

The natural gas fired boiler provides the supply steam at a nominal 100 psig (6.9 bar) pressure for operation of the PDU plant.

The superheaters employed are depicted in Figure 2-6. The first stage is a Watlow electrical heater which preheats the saturated steam from the boiler. The second stage is a coiled tube heat exchanger inserted in the PDU pulse combustor exhaust where it receives final superheat before being piped into the fluid bed.

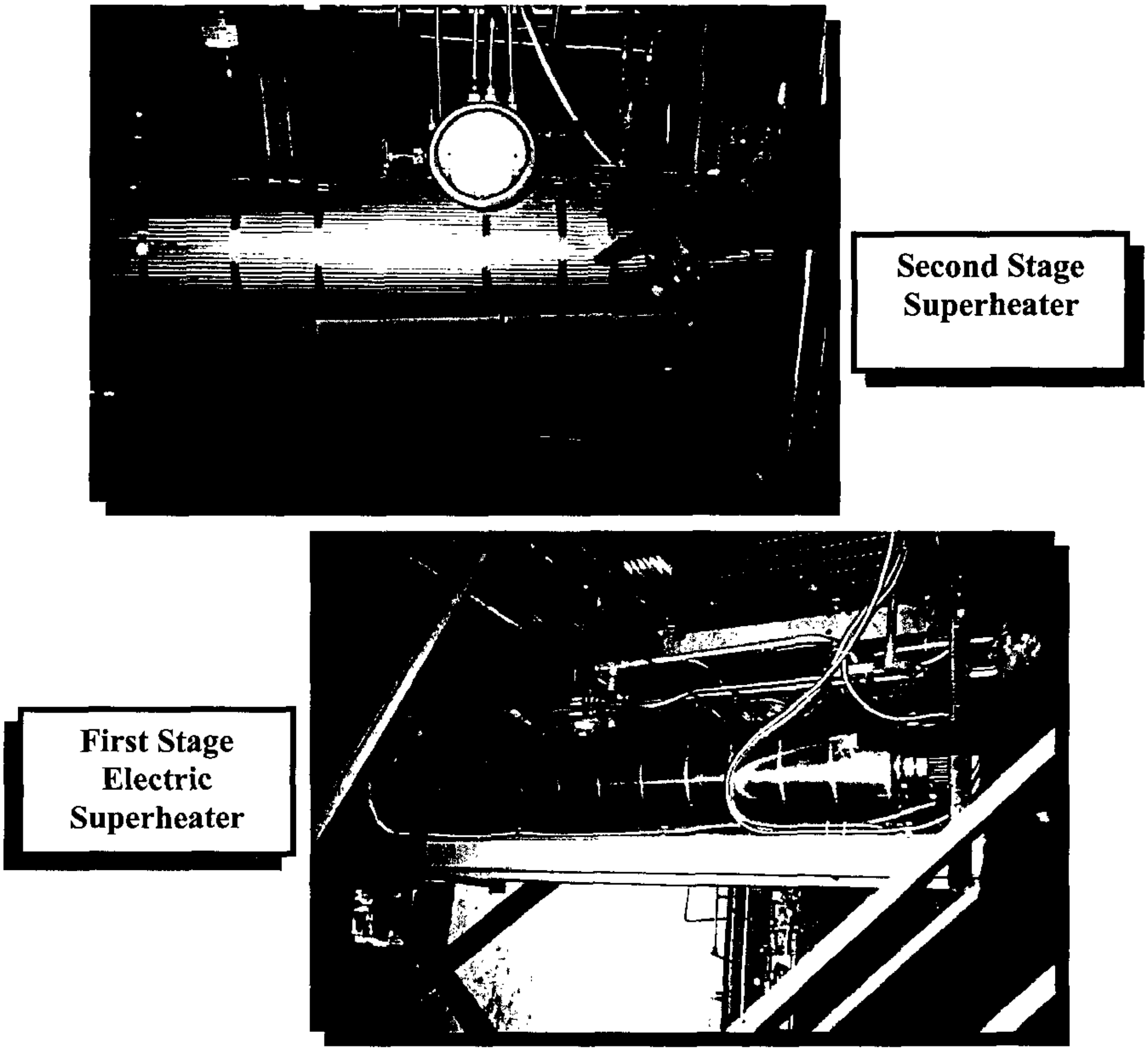



**FIGURE 2-6: SUPERHEATERS**

Typically, the steam temperature in the steam plenum is maintained at a temperature in the range of 950°F to 1,050°F.

Then the dry gas sample is passed through the GC for analysis (shown in the bottom picture of Figure 2-6). The GC operation is computer controlled with the GC data archived on the computer's hard disk.

Local analog controls (Figure 2-7) are utilized for startup, safe operation, process monitoring and control as well as for orderly startup and shutdown.

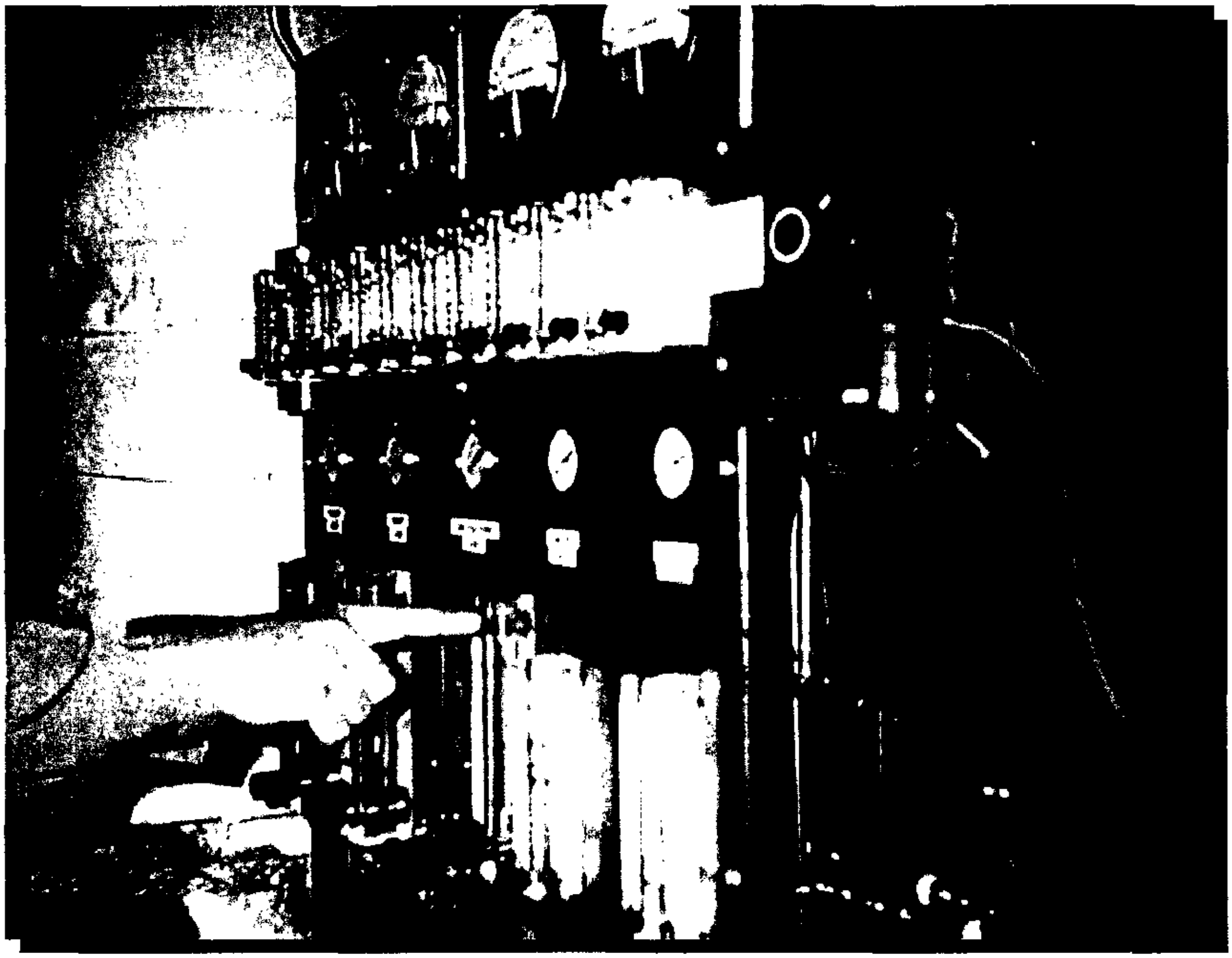


**FIGURE 2-7: STEAM REFORMER CONTROLS**

## 2.3 Proprietary Information

Proprietary data is data developed at private expense and embodies trade secrets. Clean Coal Protected Data is data first produced in the performance of this Agreement and is available to DOE. Form fit and function data or aggregated costs and performance information will be furnished in lieu of detailed proprietary information.

## 2.4 Simplified Process Flow Diagram

### 2.4.1 Combustor Design Qualification Test Facility

Figure 2-8 presents the project block flow diagram for the combustor design qualification test facility

Sand is used as the fluid bed medium. The sand is fluidized with air from five rental diesel compressors (stream no. 1). Water (stream no. 2) is injected into the bed to impose a heat load on the system to maintain the desired bed temperature. The fluidized bed off-gas (stream no. 3), comprising air used for fluidization and steam generated in the fluid-bed, passes through a cyclone for particulate collection before exiting (stream no. 4). The cyclone catch (stream no. 5) is collected in a drum for disposal.

The combustion air (stream no. 6) for the 253-tube pulse heater is delivered to the combustor by five combustion air fans. The combustor is fueled with natural gas (stream no. 7). A water spray (stream no. 9) cools the combustor flue gas (stream no. 8). The quenching spray is generated by a dual fluid atomizer using air (stream no. 10).

The cooled flue and steam are vented (stream no. 11) through a muffler.

The cooling water for the water jacket of the pulse combustor tubesheets and the aerovalve plate cooling loop is circulated via a forced circulation pump, and the water makeup is provided by stream no. 12. Steam is vented from the steam drum (stream no. 13) to maintain a desired operating pressure of approximately 450 psig.

### 2.4.2 PDU Test Facility

The block flow diagram for the PDU study is presented in Figure 2-9.

In this PDU, the coal is fed into the steam reformer (stream no. 1) near the bottom of the reactor to provide sufficient residence time in the fluid-bed.

The feeder is comprised of a feed bin with a lock hopper below it, which discharges into a live-bottom-metering bin with three metering screws.

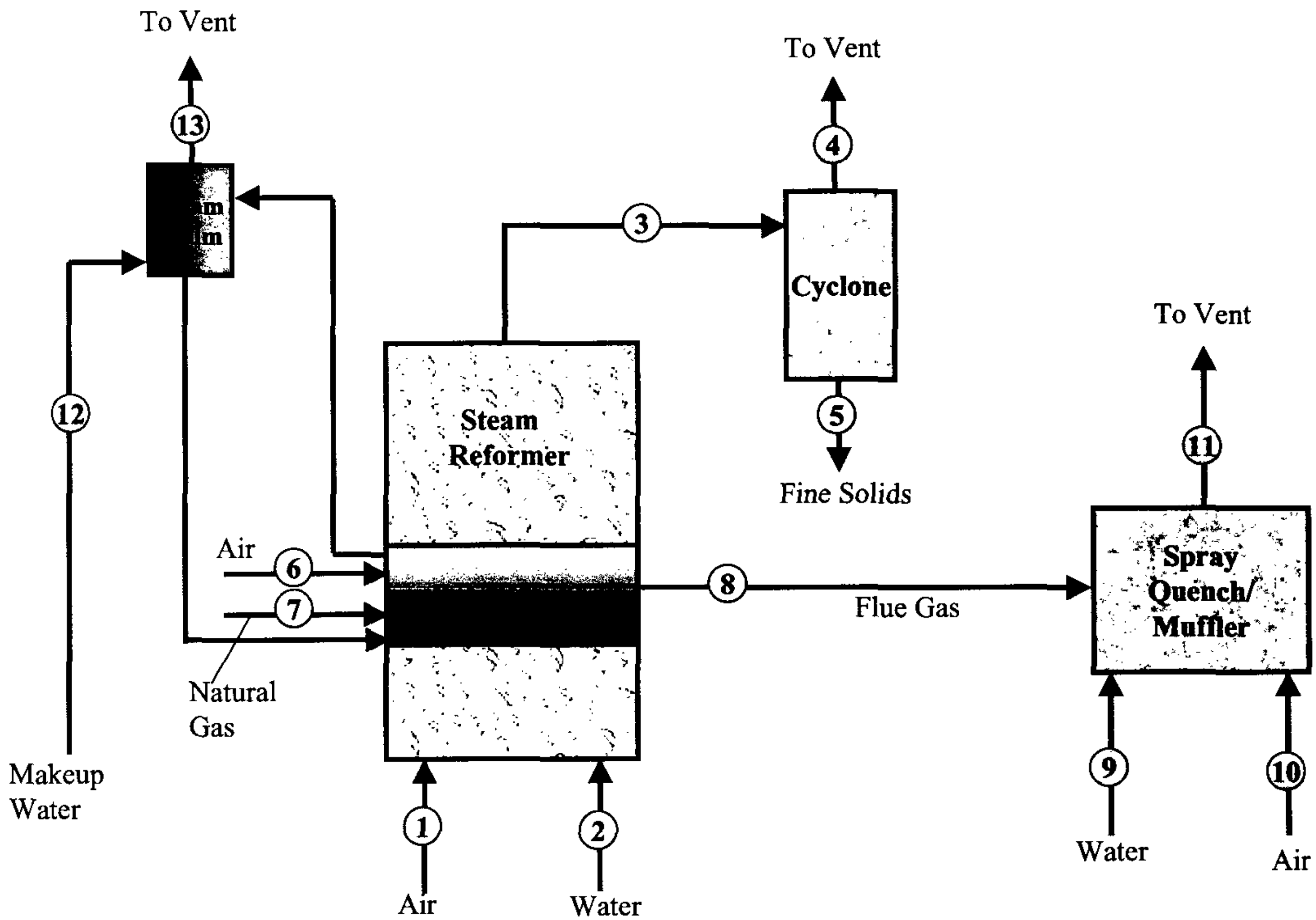



FIGURE 2-8: BLOCK FLOW DIAGRAM

Three variable speed screws meter the coal to a constant speed auger that transfer the coal into the fluid bed.

Superheated steam (stream no. 2) from the superheater is used to fluidize the reformer (R). All instrument penetrations in the reformer are purged by nitrogen (stream no. 3).

Char (stream no. 4) is extracted from the fluid-bed steam reformer and constitutes the reductant for the DRI process.

The product gas from the steam reformer passes through two stages of high efficiency cyclones (C1 and C2) and continues on to a Thermal Oxidizer (streams no. 5 and 7).

The first cyclone (C1) catch is returned to the fluid bed via a dip leg. The second cyclone fines catch (stream no. 6) is collected in a catch pot.

Natural gas (stream no. 8) is employed to fire a twin-resonance tube pulse combustor (PC). The combustion air (stream no. 9) is provided through an air plenum to the single aerodynamic valve of the pulse combustor.

The flue gas from the pulse combustor (stream no. 10) passes through the steam superheater which provides superheated steam (stream no. 12) for fluidization of the bed. The flue is sent to the stack (stream no. 11).

The thermal oxidizer employs a duct burner concept with natural gas (stream no. 13) and air (stream no. 14).

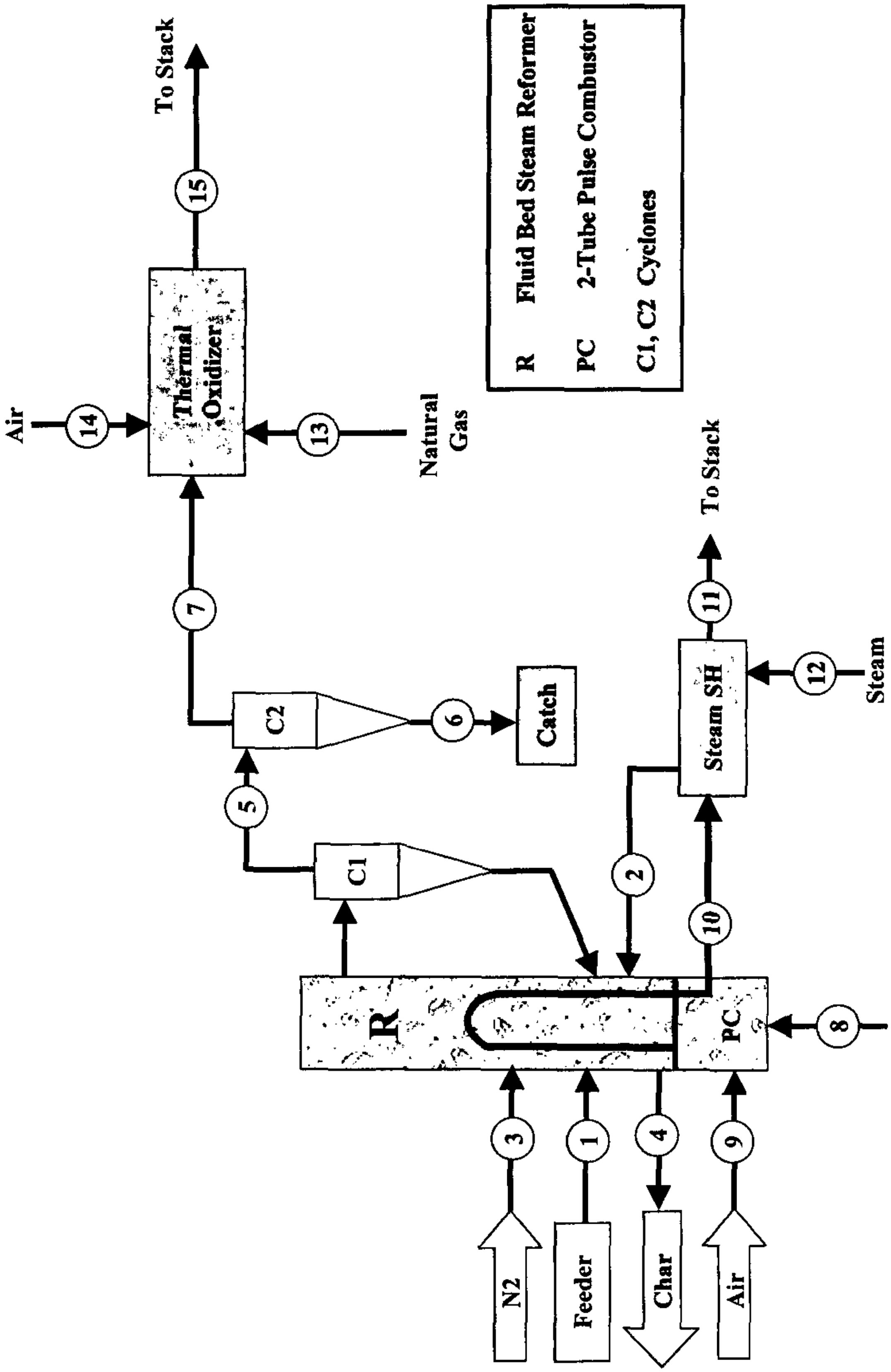



**FIGURE 2-9: PDU PROCESS FLOW DIAGRAM**

## 2.5 Stream Data

### 2.5.1 Mass and Energy Balance for the Combustor Design Qualification Test Facility

Table 2-1 presents a Mass and Energy Balance for the Combustor Design Qualification Test Facility. This is based on a test performed on March 2, 2001 without flue gas recycle.

### 2.5.2 Mass Balance for the PDU Test Facility

Table 2-2 presents a Mass Balance for the PDU Test Facility.

## 2.6 Process and Instrumentation Diagrams

### 2.6.1 P&ID for the Combustor Design Qualification Test

Figure 2-10 presents the legend sheets for the P&I Diagrams. Figures 2-11 and 2-12 present the P&ID for the Combustor Design Qualification Test. Figure 2-11, the Process and Instrumentation Diagram (P&ID), outlines the controls and instrumentation used in the Combustor Design Qualification Test facility. An ALLEN BRADLEY 5/10 Programmable Logic Controller (PLC) controlled the test facility. The PLC, in conjunction with a Fireye burner management system (BMS), tied in all the process and control loops required to operate the facility efficiently and safely. Figure 2-11 shows all the associated instrumentation utilized for the reformer including all instrumentation that was interlocked to the BMS. Figure 2-12 is the Pulse Combustor Cooling Circuit P&ID.

### 2.6.2 P&ID for the PDU Test

Figure 2-13 presents the P&ID for the PDU Test.

## TABLE 2-1: MASS & ENERGY BALANCE FOR THE COMBUS

**TEST DATE: 3/2/2**

| STREAM NO -> | | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|
| | | Air to Reformer | Water to Reformer | Gas to Cyclone | Gas to Vent | Fines to Catch Drum | Natural Gas to PC Heater |
| PRESSURE | PSIG | 5.9 | 50 | 0.3 | 0 | 0 | 1.71 |
| | IN WC | | | | | | |
| TEMPERATURE | F | 151 | 45 | 932 | 911 | 865 | 55 |
| VOLUMETRIC FLOW | GPM | | 6.0 | | | | |
| | SCFM | 2,856 | | 3,907 | 3,907 | | 287 |
| | ACFM | 2,393 | | 10,256 | 10,301 | | 255 |
| COMPONENT | | | | | | | |
| CH4 | LB/HR | | | | | | 685 |
| C2H6 | LB/HR | | | | | | 52 |
| C2H4 | LB/HR | | | | | | |
| C3H6 | LB/HR | | | | | | |
| C3H8 | LB/HR | | | | | | 25 |
| H2S | LB/HR | | | | | | |
| CH3SH | LB/HR | | | | | | |
| (CH3)2S | LB/HR | | | | | | |
| (CH3)2S2 | LB/HR | | | | | | |
| H2 | LB/HR | | | | | | |
| CO | LB/HR | | | | | | |
| CO2 | LB/HR | 6 | | 6 | 6 | | 12 |
| H2O (v) | LB/HR | 83 | | 3,082 | 3,082 | | |
| NH3 | LB/HR | | | | | | |
| O2 | LB/HR | 2,999 | | 2,999 | 2,999 | | |
| N2 | LB/HR | 9,909 | | 9,909 | 9,909 | | 6 |
| SO2 | LB/HR | | | | | | |
| H20 (l) | LB/HR | | 2,999 | | | | |
| NO | LB/HR | | | | | | |
| HCl | LB/HR | | | | | | |
| C | LB/HR | | | | | | |
| Na2CO3 | LB/HR | | | | | | |
| NaCl | LB/HR | | | | | | |
| Na2SO4 | LB/HR | | | | | | |
| Na2SO3 | LB/HR | | | | | | |
| NaHSO3 | LB/HR | | | | | | |
| Na2S | LB/HR | | | | | | |
| NaHS | LB/HR | | | | | | |
| NaHCO3 | LB/HR | | | | | | |
| NaOH | LB/HR | | | | | | |
| MF COAL | LB/HR | | | | | | |
| Inerts | LB/HR | | | 11.3 | 0.2 | 11.1 | |
| TOTAL MASS | LB/HR | 12,997 | 2,999 | 16,007 | 15,996 | 11 | 781 |
| TOTAL CARBON | LB/HR | 0 | 0 | 2 | 2 | 0 | 578 |
| TOTAL SULFUR | LB/HR | 0.000 | 0.000 | 0 | 0 | 0 | 0 |
| TOTAL SODIUM | LB/HR | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL CHLORINE | LB/HR | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| HHV | BTU/HR | 0 | 0 | 0 | 0 | 0 | 18,075,376 |
| ENTHALPY | BTU/HR | 320,716 | -95,863 | 7,263,600 | 7,157,645 | 1,922 | -8,651 |
| TOTAL HEAT | BTU/HR | 320,716 | -95,863 | 7,263,600 | 7,157,645 | 1,922 | 18,066,725 |

COMBUSTOR DESIGN QUALIFICATION TEST FACILITY

TE: 3/2/2001

| 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
|---|---|---|---|---|---|---|---|
| al Gas to Heater | Combustion Air to PC Heater | Flue Gas to Spray Quench | Water to Atomizer | Air to Atomizer | Flue Gas to Vent | Makeup Water to Steam Drum | Steam to Vent |
| | | | | | | | |
| 1.71 | | | 115 | 100 | | 450 | 397 |
| | 7 | 2 | | | 0 | | |
| 55 | 55 | 1232 | 45 | 55 | 700 | 45 | 447 |
| | | | 4.0 | | | 2.2 | |
| 287 | 4,200 | 4,496 | | 103 | 5,309 | | 382 |
| 255 | 4,089 | 14,559 | | 13 | 11,842 | | 24 |
| | | | | | | | |
| | | | | | | | |
| 685 | | 0.0 | | | 0.0 | | |
| 52 | | 0.0 | | | 0.0 | | |
| | | | | | | | |
| | | | | | | | |
| 25 | | 0.0 | | | 0.0 | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | 0.9 | | | 0.9 | | |
| 12 | 9 | 2,127 | | 0 | 2,127 | | |
| | 122 | 1,796 | | 3 | 3,823 | | 1,091 |
| | | | | | | | |
| | 4,411 | 1,392 | | 108 | 1,500 | | |
| 6 | 14,573 | 14,579 | | 357 | 14,936 | | |
| | | | | | | | |
| | | | 2,024 | | | 1,091 | |
| | | 1.7 | | | 1.7 | | |
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| | | | | | | | |
| | | | | | | | |
| 781 | 19,115 | 19,896 | 2,024 | 468 | 22,388 | 1,091 | 1,091 |
| 578 | 2 | 581 | 0 | 0 | 581 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | | | | | | |
| 075,376 | 0 | 4,558 | 0 | 0 | 4,558 | 0 | 0 |
| -8,651 | 26,590 | 8,277,469 | -64,688 | 651 | 8,011,307 | -34,880 | 1,333,341 |
| | | | | | | | |
| 066,725 | 26,590 | 8,282,027 | -64,688 | 651 | 8,015,865 | -34,880 | 1,333,341 |

## TABLE 2-2: MASS BALANCE FOR T

| | | | 1000°F TEST | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| COMPONENT | UNITS | FORMULA | COAL | STEAM | NITROGEN PURGE | PRODUCT GAS | CHAR | COAL | S |
| Hydrogen | Lb/Hr | H2 | | | | 0.569 | | | |
| Nitrogen | Lb/Hr | N2 | | | 19.518 | 19.691 | | | |
| Methane | Lb/Hr | CH4 | | | | 2.324 | | | |
| Carbon Monoxide | Lb/Hr | CO | | | | 0.825 | | | |
| Carbon Dioxide | LB/Hr | CO2 | | | | 10.955 | | | |
| Ethylene | Lb/Hr | C2H4 | | | | 0.561 | | | |
| Ethane | Lb/Hr | C2H6 | | | | 0.625 | | | |
| Acetylene | Lb/Hr | C2H2 | | | | 0.000 | | | |
| Hydrogen Sulfide | Lb/Hr | H2S | | | | 0.083 | | | |
| Propylene | Lb/Hr | C3H6 | | | | 0.365 | | | |
| Propane | Lb/Hr | C3H8 | | | | 0.000 | | | |
| Steam | Lb/Hr | H2O | | 23.361 | | 40.941 | | | 27. |
| Coal | Lb/Hr | | 52.000 | | | | | 45.000 | |
| Char | Lb/Hr | | | | | | 30.645 | | |
| Condensables | Lb/Hr | | | | | 0.331 | | | |
| | | | | | | | | | |
| TOTAL MASS | Lb/Hr | ---- | 52.000 | 23.361 | 19.518 | 77.270 | 30.645 | 45.000 | 27. |

## TABLE 2-2: MASS BALANCE FOR THE PDU TEST FACILITY

| F TEST | | | 1100°F TEST | | | | | 12 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| OGEN RGE | PRODUCT GAS | CHAR | COAL | STEAM | NITROGEN PURGE | PRODUCT GAS | CHAR | COAL | STEAM | N |
| | 0.569 | | | | | 0.634 | | | | |
| ·18 | 19.691 | | | | 13.308 | 13.458 | | | | 1 |
| | 2.324 | | | | | 1.814 | | | | |
| | 0.825 | | | | | 0.988 | | | | |
| | 10.955 | | | | | 9.462 | | | | |
| | 0.561 | | | | | 0.466 | | | | |
| | 0.625 | | | | | 0.369 | | | | |
| | 0.000 | | | | | 0.002 | | | | |
| | 0.083 | | | | | 0.054 | | | | |
| | 0.365 | | | | | 0.238 | | | | |
| | 0.000 | | | | | 0.000 | | | | |
| | 40.941 | | | 27.117 | | 41.963 | | | 18.618 | |
| | | | 45.000 | | | | | 32.000 | | |
| | | 30.645 | | | | | 25.826 | | | |
| | 0.331 | | | | | 0.268 | | | | |
| | | | | | | | | | | |
| 518 | 77.270 | 30.645 | 45.000 | 27.117 | 13.308 | 69.716 | 25.826 | 32.000 | 18.618 | |

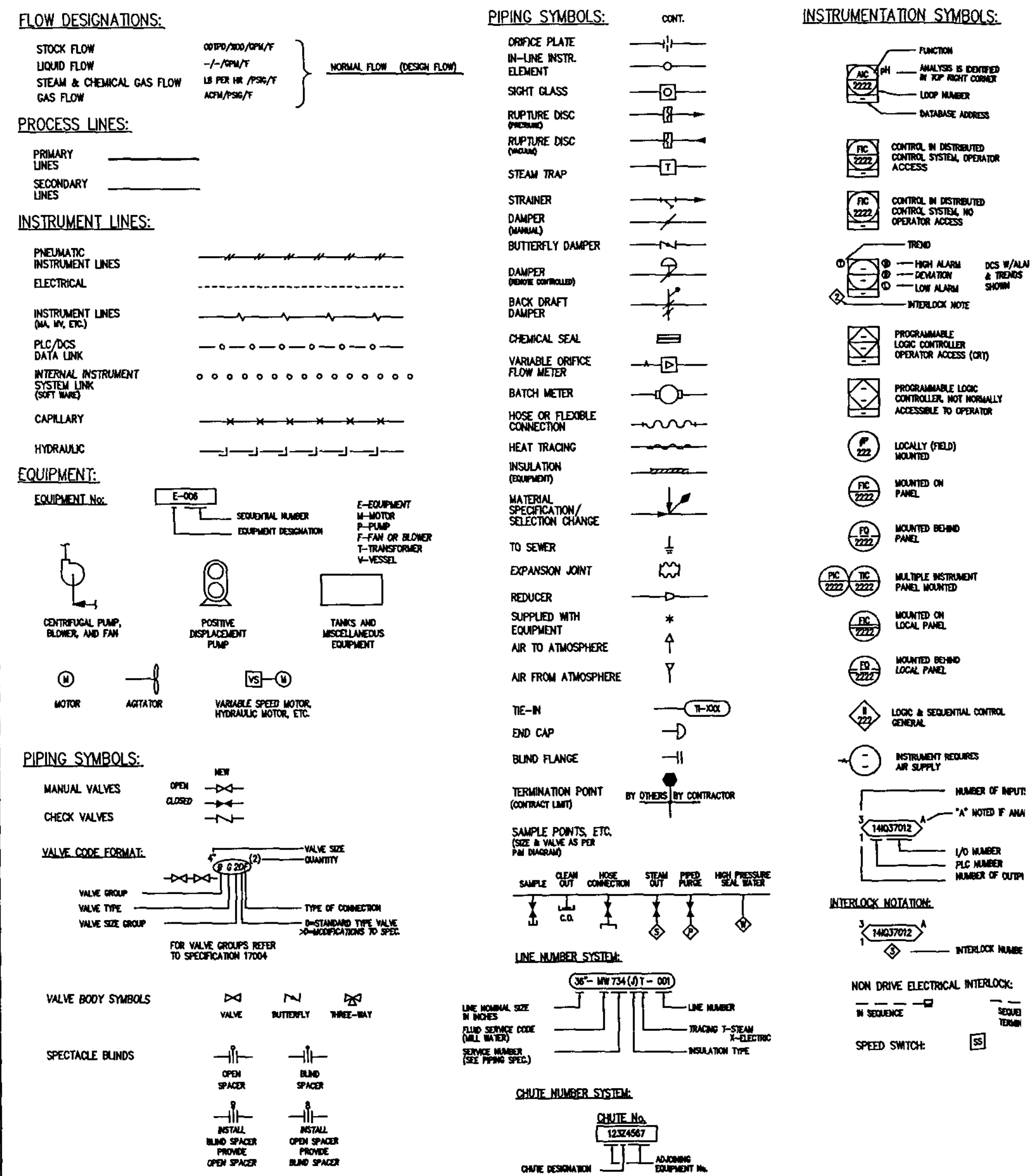







**FIGURE 2-10: Legend Sheet No. 1 for**

## IION SYMBOLS:

— FUNCTION
— ANALYSIS IS IDENTIFIED IN TOP RIGHT CORNER
— LOOP NUMBER
— DATABASE ADDRESS

NTROL IN DISTRIBUTED NTROL SYSTEM, OPERATOR CCESS

NTROL IN DISTRIBUTED NTROL SYSTEM, NO ERATOR ACCESS

- TREND

— HIGH ALARM
— DEVIATION
— LOW ALARM

DCS W/ALARMS & TRENDS SHOWN

- INTERLOCK NOTE

ROGRAMMABLE OGIC CONTROLLER PERATOR ACCESS (CRT)

ROGRAMMABLE LOGIC ONTROLLER, NOT NORMALLY CCESSIBLE TO OPERATOR

OCALLY (FIELD) OUNTED

OUNTED ON ANEL

OUNTED BEHIND ANEL

ULTIPLE INSTRUMENT ANEL MOUNTED

OUNTED ON OCAL PANEL

OUNTED BEHIND OCAL PANEL

OIC & SEQUENTIAL CONTROL NERAL

STRUMENT REQUIRES R SUPPLY

—— NUMBER OF INPUTS
2 A —— "A" NOTED IF ANALOG
—— I/O NUMBER
—— PLC NUMBER
—— NUMBER OF OUTPUTS

ION:

A

—— INTERLOCK NUMBER

CTRICAL INTERLOCK:

SEQUENCE TERMINATION

SS

## MISC. ABBREVIATION & ACRONYMS

A — ANALOG SIGNAL
AC — AIR TO CLOSE
AE — ABANDON EXISTING
AO — AIR TO OPEN
AVG — AVERAGE
CASC — CASCADE
DCS — DISTRIBUTED CONTOL SYSTEM
DIFF — SUBTRACT
DIR — DIRECT-ACTING
E/I — VOLTAGE/CURRENT
EC — ENERGIZE TO CLOSE
EO — ENERGIZE TO OPEN
ES — ELECTRIC SUPPLY
ESD — EMERGENCY SHUTDOWN
FC — FAIL CLOSED
FL — FAIL LOCKED OR LAST
FO — FAIL OPEN
H — HYDRAULIC SIGNAL
HS — HYDRAULIC SUPPLY
I — INPUT OF INTERLOCK
IA — INSTRUMENT AIR SUPPLY
I/I — CURRENT/CURRENT
I/P — CURRENT/PNEUMATIC
MA — MILL AIR SUPPLY
MO — MOTOR OPERATED
NC — NORMALLY CLOSED
NO — NORMALLY OPEN
No. — NUMBER
O — OUTPUT OR OPENED
P — PNEUMATIC SIGNAL OR PROPORTIONAL CONTROL MODE
P/I — PNEUMATIC/CURRENT
PLC — PROGRAMMABLE LOGIC CONTROLLER
R — AUTOMATIC-RESET CONTROL MODE, RESET OF FAIL-LOCKED DEVICE, OR RESISTANCE (SIGNAL)
RE — REPLACE EXISTING
REV — REVERSE-ACTING
RTD — RESISTANCE TEMPERATURE DETECTOR
S — SOLENOID ACTUATOR
SP — SET-POINT
SQ.RT. — SQUARE ROOT
SS — STEAM SUPPLY
T — TRAP
TC — THERMOCOUPLE
TW — THERMOWELL
WS — WATER SUPPLY
X — CLOSED

## ANALYSIS ABBREVIATIONS

COMB. — COMBUSTIBLES
GC — GAS CHROMATOGRAPH
$H_2$ — HYDROGEN
$O_2$ — OXYGEN
$CO_x$ — CARBON OXIDES
$NO_x$ — NITROGEN OXIDES
$SO_x$ — SULFUR OXIDES
$CL_2$ — CHLORINE
$H_2S$ — HYDROGEN SULFIDE
BRITE — BRIGHTNESS
LEL — LOWER EXPLOSIVE LIMIT
pH — pH
TOC — TOTAL ORGANIC CARBON
TC — TOTAL CARBON
BOD — BIOLOGICAL OXYGEN DEMAND
DO — DISSOLVED OXYGEN
FL — FLUORIDE
ORP — OXIDATION/REDUCTION POTEN
RES — RESIDUAL CHEMICAL
BMS — BURNER MANAGEMENT SYSTEM
BF — BURNER FLAME
MOIS — MOISTURE

## SERVICE DESIGNATIONS

APG — PLANT AIR
ASH — ASH
C01 — CONDENSATE, 150# CLASS
GF — FLUE GAS
GP — PRODUCT GAS
NGA — NATURAL GAS
NGI — NITROGEN
S01 — STEAM, 150# CLASS
SAN — SAND
WB1 — WATER, BOILER FEED, 150# CLASS
WCR — WATER, CHILLED, RETURN
WCS — WATER, CHILLED, SUPPLY
WHA — WATER, HOT
WMA — WATER, MILL
WSR — WATER, RAW

## INSTRUMENTATION ABBREVIATIONS:

F I C

| | FIRST LETTER | | SUCCEEDING LETTERS | |
|---|---|---|---|---|
| | MEASURED OR INITIATED VARIABLE | MODIFIER | READOUT PASSIVE & OUTPUT FUNCTION | MODIFIER |
| A | ANALYSIS | | ALARM | |
| B | BURNER FLAME | | USER'S CHOICE | |
| C | CONDUCTIVITY | | CONTROL | |
| D | DENSITY | DIFFERENTIAL | DEVIATION/DRIVE | CLOSED |
| E | VOLTAGE/EVENT | | SENSOR (PRIMARY ELEMENT) | |
| F | FLOW | RATIO | RATIO | |
| G | GAUGE THICKNESS | | GLASS GAUGE | |
| H | MANUAL, HAND | | | HIGH |
| I | CURRENT | | INDICATE | |
| J | POWER (WATTS) | SCAN | | |
| K | TIME | | CONTROL STATION | |
| L | LEVEL | | LIGHT | LOW |
| M | MOISTURE, HUMIDITY | | MONITOR | INTERMEDIATE |
| N | CONSISTENCY | | USER'S CHOICE | |
| O | USER'S CHOICE, OPACITY | | ORIFICE | OPEN |
| P | PRESSURE OR VACUUM | | POINT (TEST) CONNECTION | |
| Q | QUANTITY | TOTALIZER | INTEGRATOR, TOTALIZER | |
| R | RESTRICTION/RESISTANCE | | RECORD OR PRINT/REGULATOR | |
| S | SPEED | SAFETY | SWITCH/SELECTOR | |
| T | TEMPERATURE/TORQUE | | TRANSMITTER | |
| U | MULTI-VARIABLE | | MULTI-FUNCTION | MULTI-FUNCTION |
| V | VISCOSITY/VIBRATION/VIDEO | | VALVE, DAMPER OR LOUVER | |
| W | WEIGHT OR FORCE | | WELL | |
| X | MANUAL ON/OFF (VARS) | | UNCLASSIFIED | UNCLASSIFIED |
| Y | USER'S CHOICE | | RELAY, COMPUTE, OR CONVERT | |
| Z | POSITION, LIMIT | | ACTUATOR, DRIVER | |

# LOCAL INDICATION (#P-PRESSURE, #L-LEVEL, #F-FLOW, #T-TEMPERATURE)

## INSTRUMENT NOTES:

1. ALL DCS POINTS WILL BE TRENDED.
2. ALL DCS POINTS WILL HAVE HIGH & LOW ALARMS.
3. ALL MOTOR START/STOP FROM DCS UNLESS INDICATED OTHERWISE.

| REV | DATE | DESCRIPTION | |
|---|---|---|---|
| D | 10MAR00 | ISSUED FOR DESIGN | GN |
| C | 12NOV98 | ISSUE FOR APPROVAL | PC |
| B | 05NOV98 | ISSUE FOR REVIEW | EL |
| A | 26OCT98 | ISSUE FOR REVIEW | EL |

ThermoChem Inc.

6001 CHEMICAL ROAD BALTIMORE, MD 21226

INDUSTRA Engineers & Consultants

SEATTLE WA. PORTLAND OR. GREENVILLE S.C.

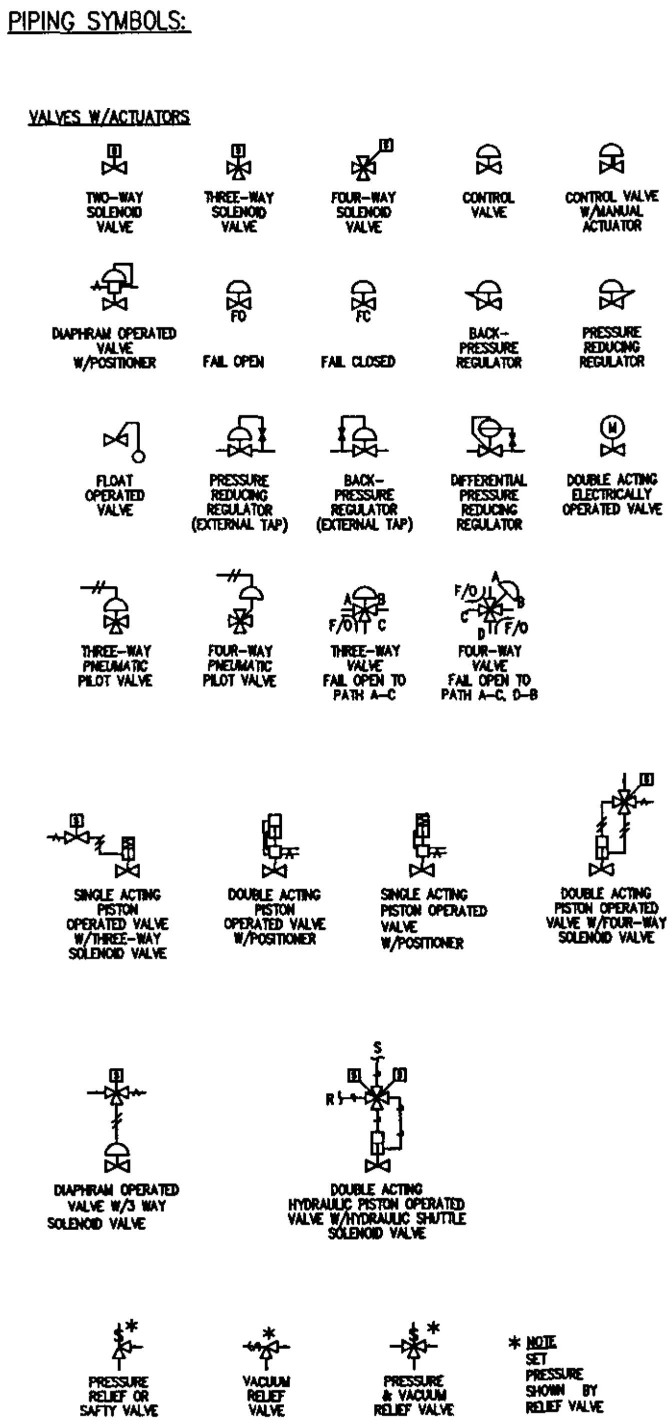
PROJECT NO. 11805

DEMONSTRATION PLANT
P & I DIAGRAM
LEGEND-SHEET 1

| SCALE | DATE | DRAWING NO. |
|---|---|---|
| NONE | 23OCT98 | D-11805-F-001 |
| DR. BY | PROJ. NO. | |
| ELM | 11805 | |



1 for the P&I Diagram



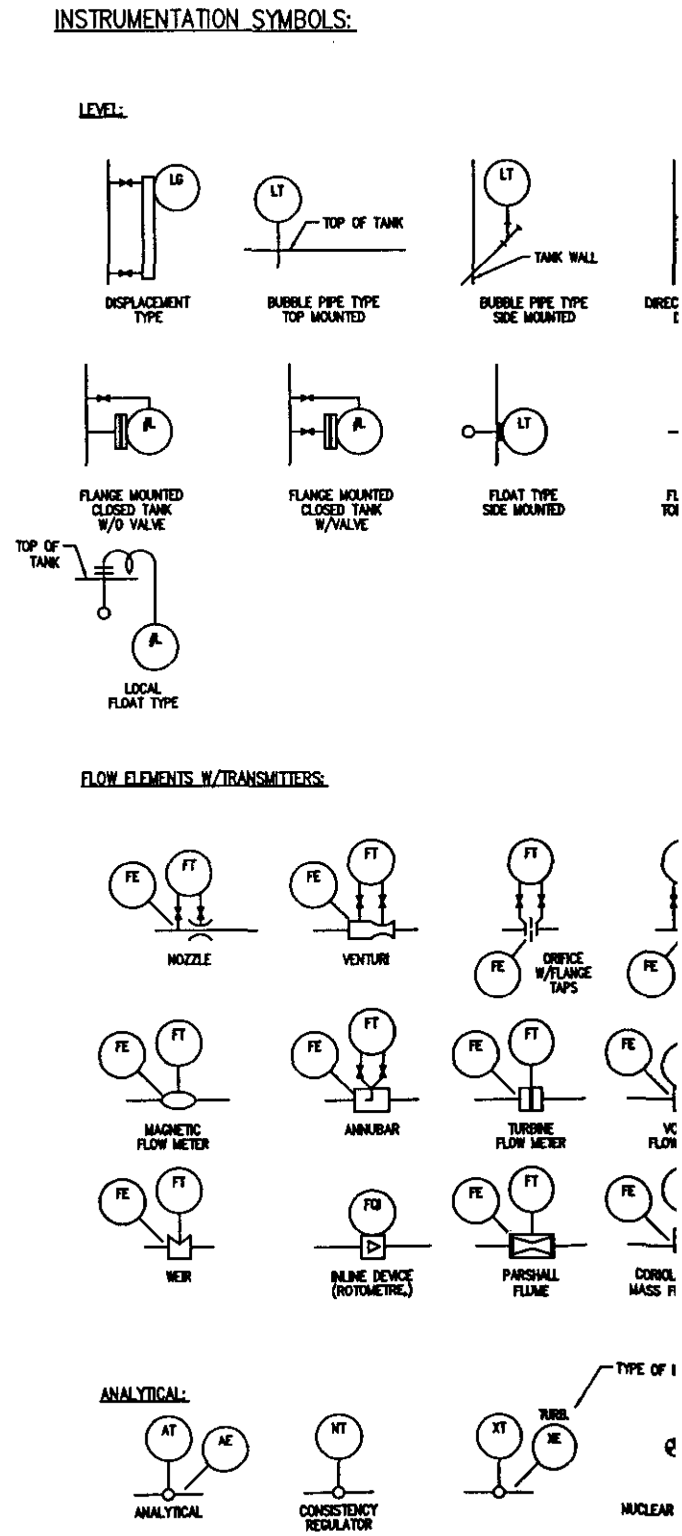
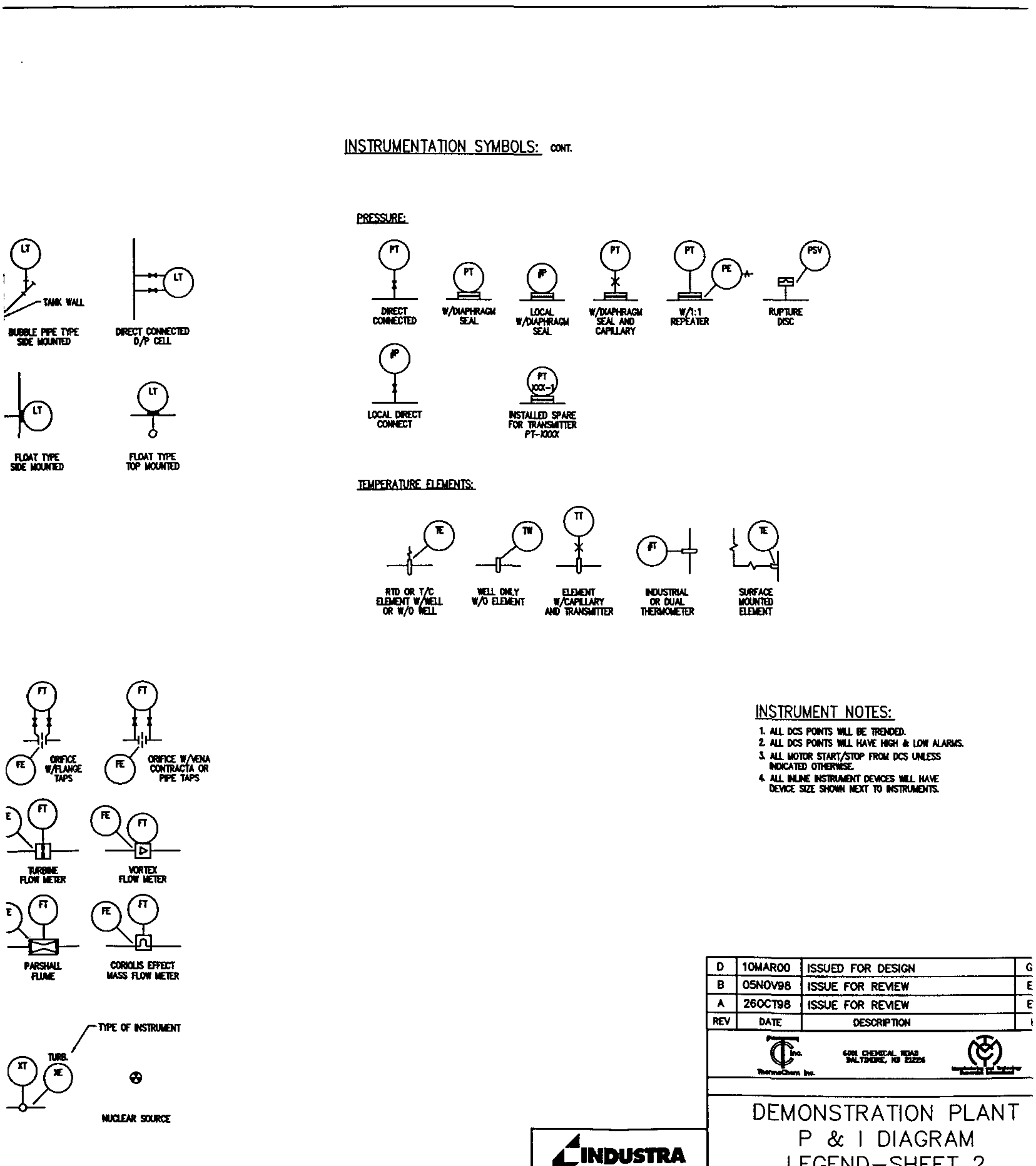




**FIGURE 2-10 (continued): Legend Sheet No. 2 for the P&I**




**for the P&I Diagram**

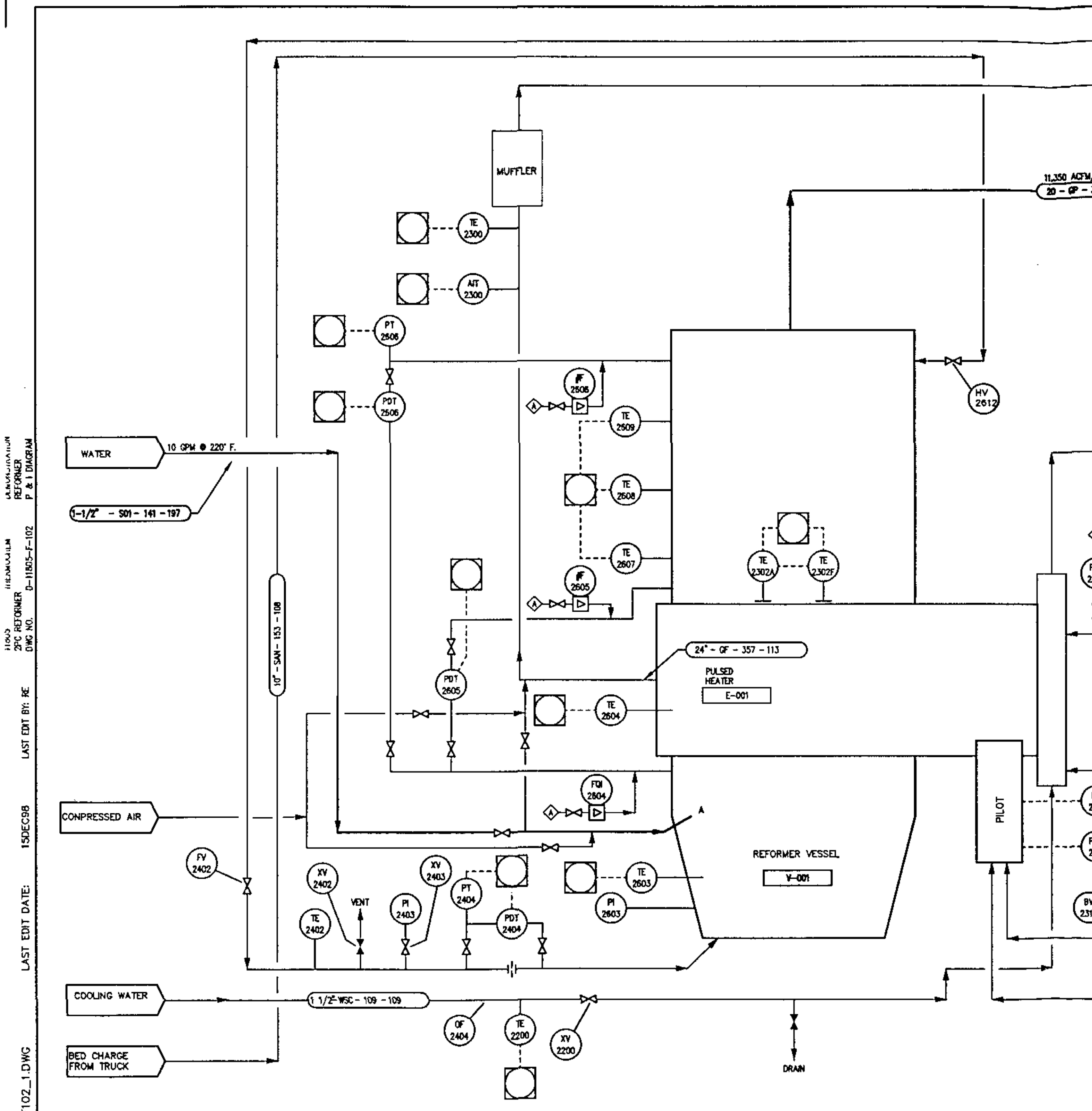
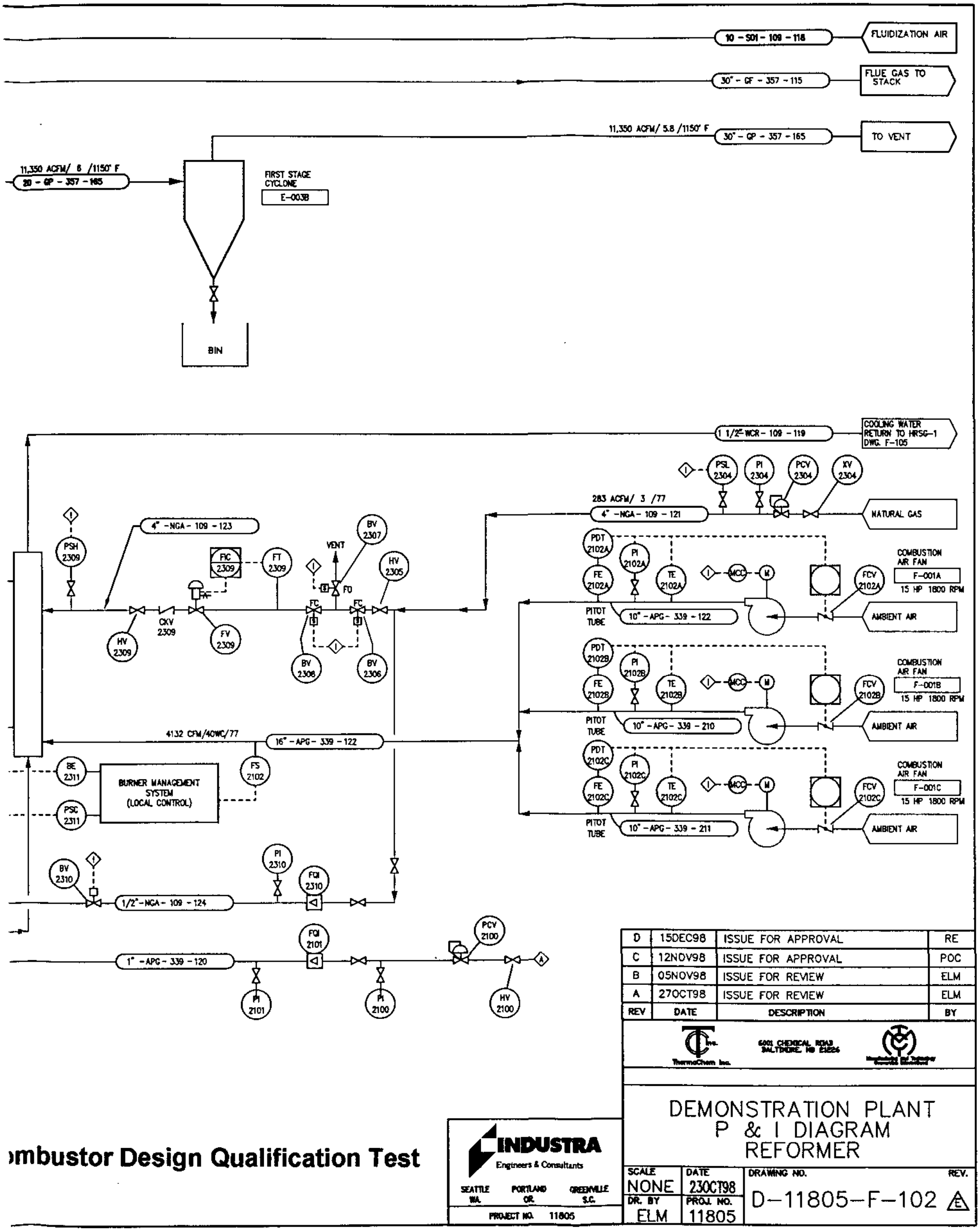



**FIGURE 2-11: Process and Instrumentation Diagram for the Combus**




**…mbustor Design Qualification Test**

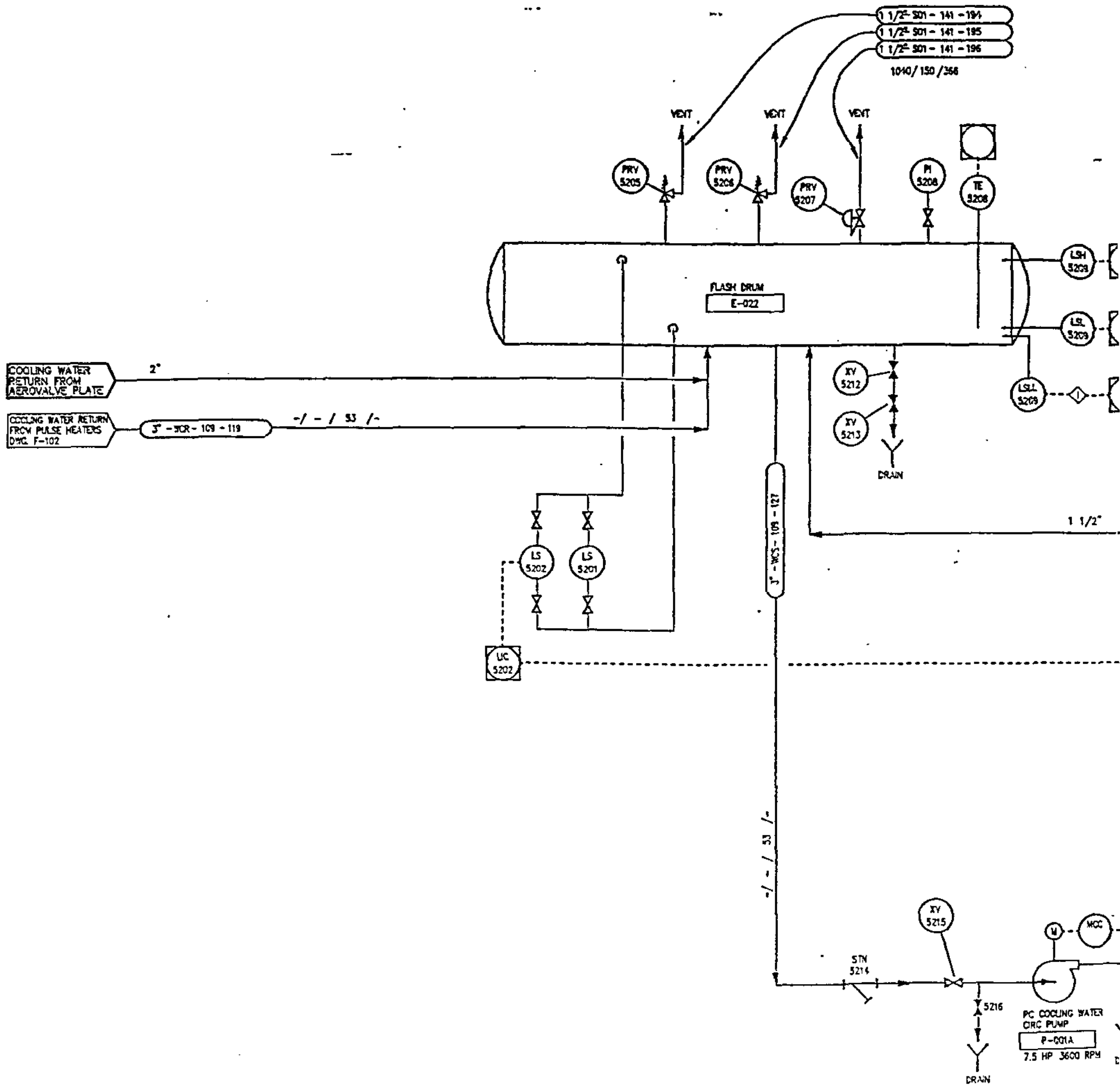
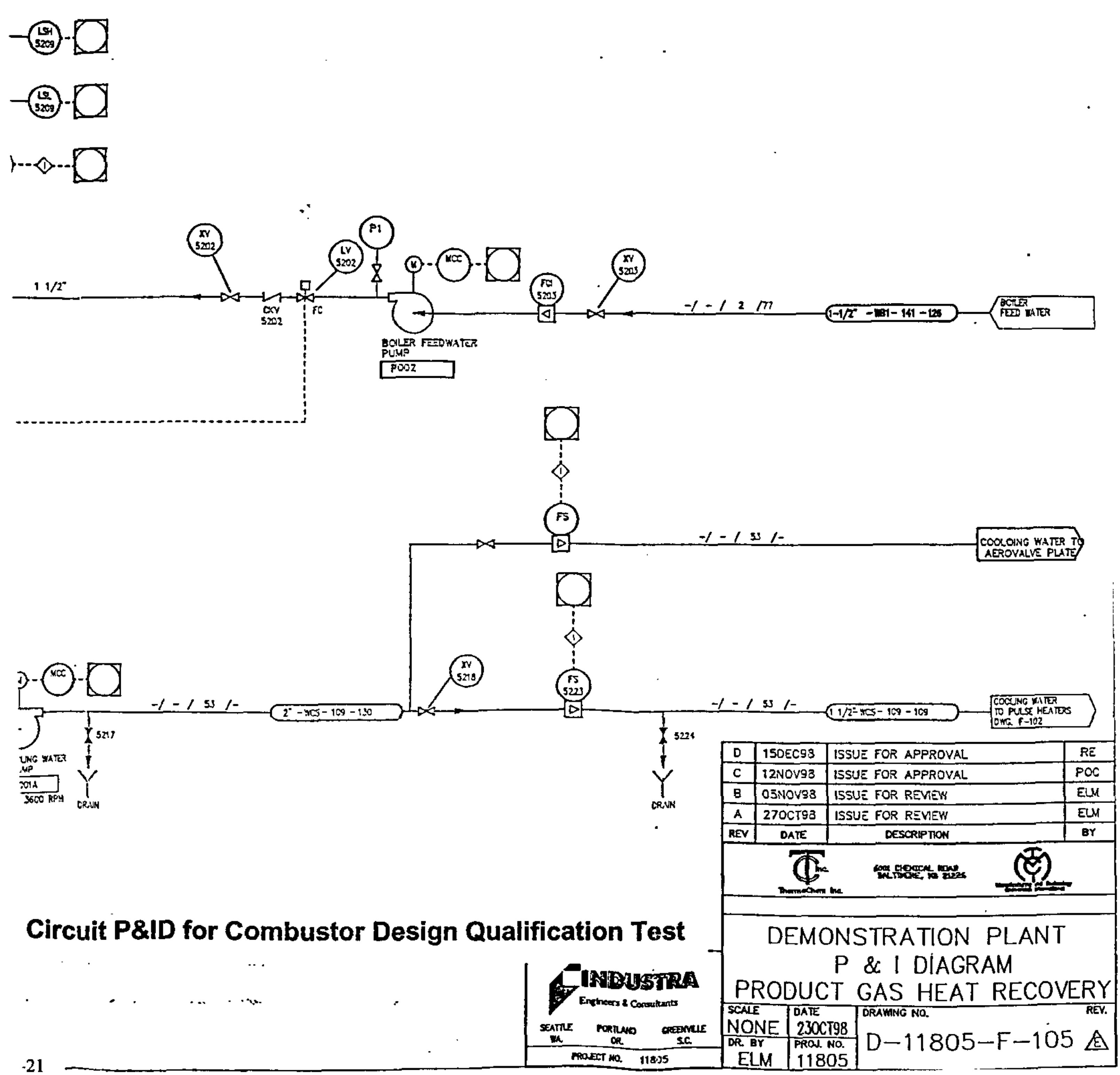



FIGURE 2-12 : Pulse Combustor Cooling Circ




**Circuit P&ID for Combustor Design Qualification Test**

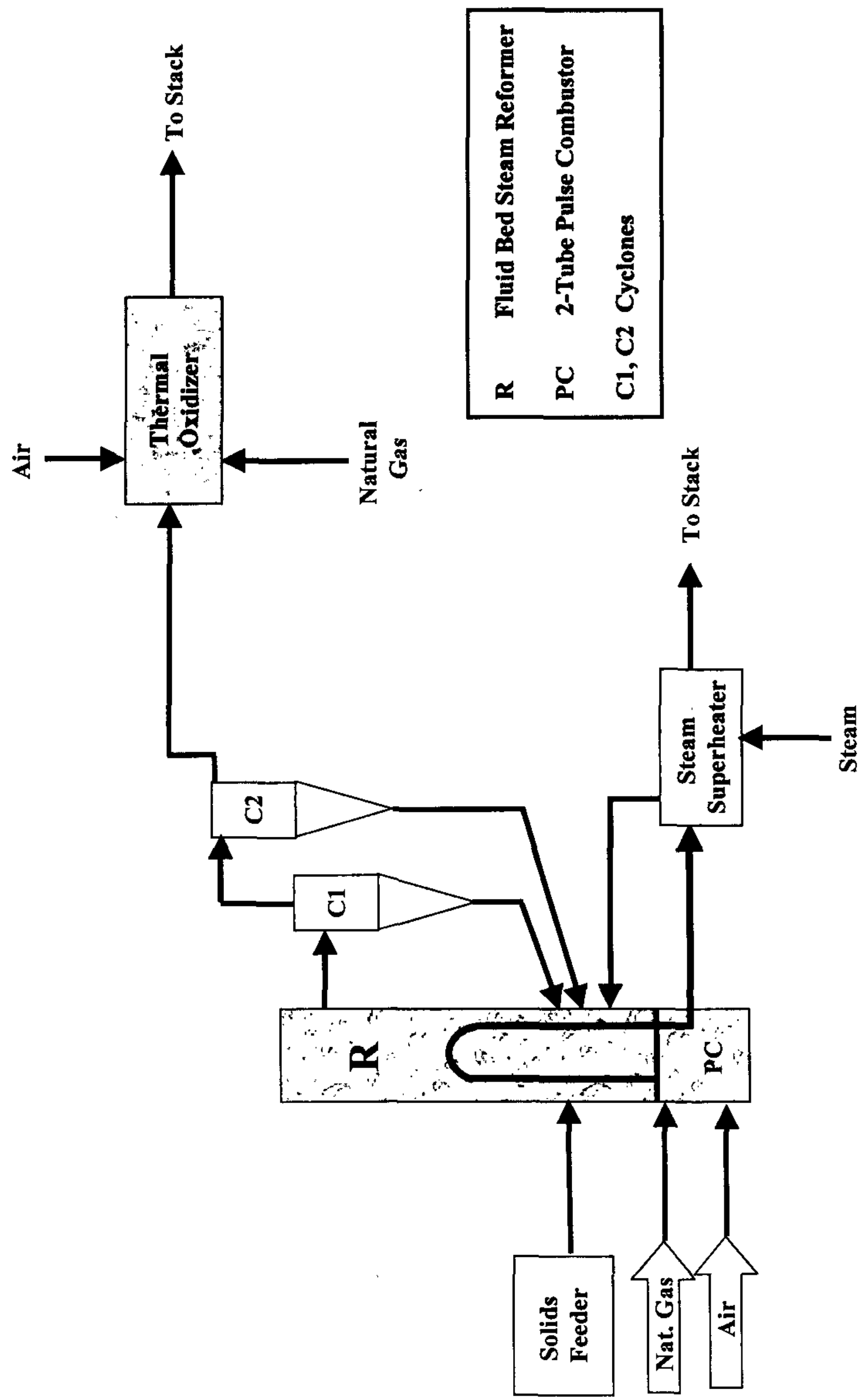



FIGURE 2-13: Process and Instrumentation Diagram for the PDU Test

# 3.0 UPDATE OF THE PUBLIC DESIGN REPORT

## 3.1 Design and Equipment Changes

The design and equipment are unchanged from the original Public Design Report, Volume I.

## 3.2 Demonstration Plant Capital Costs Update

The capital cost analysis presented in Volume I is unchanged.

# 4.0 DEMONSTRATION PROGRAM

## 4.1 Test Plans

The principal objectives of this program were to perform qualification testing of a 253-tube pulsed heater and to demonstrate its readiness for commercial deployment.

The specific objectives included verification and demonstration of:

- Full-scale pulsed heater performance and operability,
- Steam reformer system performance and operability,
- Thermal and gasification efficiency with coal feed into the PDU,
- Emissions ($SO_2$, $NO_X$, THC and CO) determination, and
- Waste stream (effluent) regulatory compliance for samples from the PDU.

Tests were conducted in two separate facilities to develop the data required to commercialize the pulse heater technology. Full-scale heater performance was assessed in the Pulse Combustor Test Facility. Process data, i.e., product gas yields and composition, char yields and composition and endothermic heat requirements were determined in the PDU.

### 4.1.1 Combustor Qualification Tests

Performance of a full-scale multiple resonance tube pulse combustor was determined in the test facility constructed as part of this project.

The test plan is presented in Appendix A.

The pulse combustor's role in the reformer is to provide the process heat required. The combustor was test fired on natural gas. The amount of heat that can be supplied by the pulse combustor will be determined at various operating conditions. Combustor firing rate and excess air levels are the variables to be examined with respect to the combustor. Of course, the amount of heat that can be transferred to the fluidized bed is also dependent upon the conditions within the bed (bedside heat transfer coefficient) and the tube-to-bed temperature difference. The tube temperatures and bed temperatures were monitored and used in conjunction with energy balance data to determine the bedside heat transfer coefficient. Combustor efficiency and emissions were determined at various firing rates (up to 25 million Btu/hr), excess air levels (20% to 60%), and fluidized bed operating temperatures (1,100°F to 1,400°F). The test matrix is presented in the following table.

### Table 4-1: Test Matrix

NUMBER OF TEST SERIES PERFORMED: 6

| VARIABLE | VALUE OR RANGE |
|---|---|
| **PULSED HEATER:** | |
| FIRING RATE, MMBTU/H | 4 - 23 |
| FLUE GAS RECYCLE | NO;<br>YES |
| INNER SHIELD TUBE | LONG (26 INCH LENGTH);<br>SHORT (5 INCH LENGTH) |
| FUEL | NATURAL GAS;<br>H2 - RICH SYN GAS |
| **HEAT SINK:** | |
| - AIR FLUIDIZED BED<br>BED TEMPERATURE, F | 50 - 1,350 |
| - WATER BATH<br>TEMPERATURE, F | 212 |

The fluidized bed test facility was filled with sand and fluidized with air. Water was injected into the bed to impose a heat load, thereby controlling the bed temperature independently of combustor firing rate. Gas flow and combustion airflow rates were measured for each test. The pulse combustor flue gas was analyzed to determine the concentration of oxygen, carbon monoxide, carbon dioxide, nitrogen oxides, sulfur dioxides, and hydrocarbons. This data was used to assess combustion efficiency at various firing rates and excess air levels and provided the basis for the commercial configuration system using this general combustor design.

The fluidized bed temperature, fluidizing air flow, water flow for bed temperature control, pulse combustor exhaust temperature, resonance tube temperatures, combustion air temperature and combustor cooling circuit steam generation were measured for each test. This data permitted projections of an energy balance and quantification of the amount of heat transferred to the bed and the tube-to-bed heat transfer coefficient.

Performance of a full-scale multiple resonance tube pulse combustor was determined in the test facility constructed as part of this project. The combustor was fired on natural gas for most of the testing program.

The amount of heat that can be supplied by the pulse combustor was determined at several firing rates and excess air levels. The tube temperatures and bed temperatures were monitored and used in conjunction with energy balance data to determine the bed-side heat transfer coefficient. Combustor efficiency and emissions ($SO_2$, $NO_X$, THC and CO) were determined at various firing rates, excess air levels, recycle flue gas rates, and fluidized bed operating temperatures.

### 4.1.2 Coal Characterization Tests

The production of char in the PDU for DRI is the basis for selecting the coal to be tested in the PDU. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant.

In the char production application, the primary variable will be operating temperature. The goal is to identify the lowest temperature at which satisfactory sulfur and volatile matter content reduction is achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby increasing product yield. The lower operating temperature also provides a higher tube-to-bed temperature differential, which improves the amount of heat transfer into the reformer and increases throughput.

The objective of these tests, conducted in an existing PDU, was to identify the lowest temperature at which a char suitable for use as a reductant for DRI production could be achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby maximizing solid product yield. Three operating temperatures were evaluated: 1000, 1100, and 1200 °F.

Mass and energy balances were performed for each steady state PDU test to verify mass closure and to determine the process heat requirement. The coal feed rate, fluidizing steam rate, and instrument purge (nitrogen) rates were measured for each test. A slipstream of product gas was collected in an EPA Method 5 impinger train and the steam and condensable hydrocarbons are collected for analysis. Fixed gas composition was determined by on-line gas chromatography. Product char was collected and analyzed for comparison. The fluid-bed temperature distribution was monitored by thermocouples inserted in thermal wells, so as to permit replacement of thermocouples during operation. The locations of the thermocouples were selected to span the fluid bed such that any maldistribution in fluidization and bed temperature uniformity can be detected.

Since the fluid bed removes heat from the resonance tubes of the pulse combustor, uniform bed fluidization is important in maintaining uniform tube temperatures and efficient heat flux and heat transfer conditions from the resonance tubes to the bed. The bed height was measured by two sets of pressure differential measurements. The pressure differential between two locations at a known height between the two pressure-monitoring taps in the bed were employed to monitor the expanded bed density (pressure drop per unit bed height).

Samples of the product gas condensate were submitted to an independent laboratory for analysis. On-line gas chromatography was utilized to determine product gas composition, yield and heating value. Employing the PDU's semi-automated data acquisition system, all process variables were data logged every thirty (30) minutes to develop trend information. The product gas composition (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, methane, acetylene, ethylene, ethane, propylene, and propane were determined on line with the MTI M-200 gas chromatograph. Draeger tubes were employed to monitor ammonia and hydrogen sulfide in the product gas. Utilizing an EPA Method 5 gas sampling train, product gas condensate samples were collected, quantified and submitted to an independent laboratory for analysis. Laboratory determinations included volatile organic compounds (VOC's), semi-volatile organic compounds (SVOC's), Chemical Oxygen Demand (COD), Biological Oxygen Demand (BOD), chloride, sulfur and nitrogen compounds.

## 4.2 Operating Procedures

Instrumentation and Data Acquisition Systems and Test Methods used in completing the tests are described in this section.

The Design Qualification Test Checkout Procedure is presented in Appendix B.

### 4.2.1 Instrumentation and Data Acquisition

For the Design Qualification Tests, most of the data was recorded every five minutes in the PLC control and data system. The fluidized bed temperature, fluidizing air flow, pulse combustor exhaust temperature, resonance tube temperature, combustion air temperature, pulse combustor fuel flow, combustion air flow, and recycle flue gas flow were recorded automatically. Water injected into the fluidized bed for temperature control, make-up water for the steam generation circuit, and fluidized bed shell temperatures were measured and recorded manually. Flue gas composition was measured continuously and recorded every five minutes.

For the PDU tests, all temperature and pressure data were recorded manually at thirty-minute intervals. Natural gas and airflow to the pulse combustor and instrument purge nitrogen were measured by rotameters and recorded manually. An approximate instantaneous coal feed rate was determined by observing the metering screw speed. However, the actual coal feed rate is obtained by direct weighing of the coal fed into the loading hopper over time. Cyclone product was collected at the end of each test and weighed to determine a production rate. The bed solids were weighed before and after each test to determine the amount of char that stays in the bed. Product gas composition was measured by an on-line gas chromatograph which stores data every five minutes during the test.

## 4.3 Test Methods

For the coal characterization tests, an on-line GC was used to analyze a small slipstream of the product gas flow. The sample product gas flow was first passed through a gas cleanup system, shown at the top of Figure 4-1.

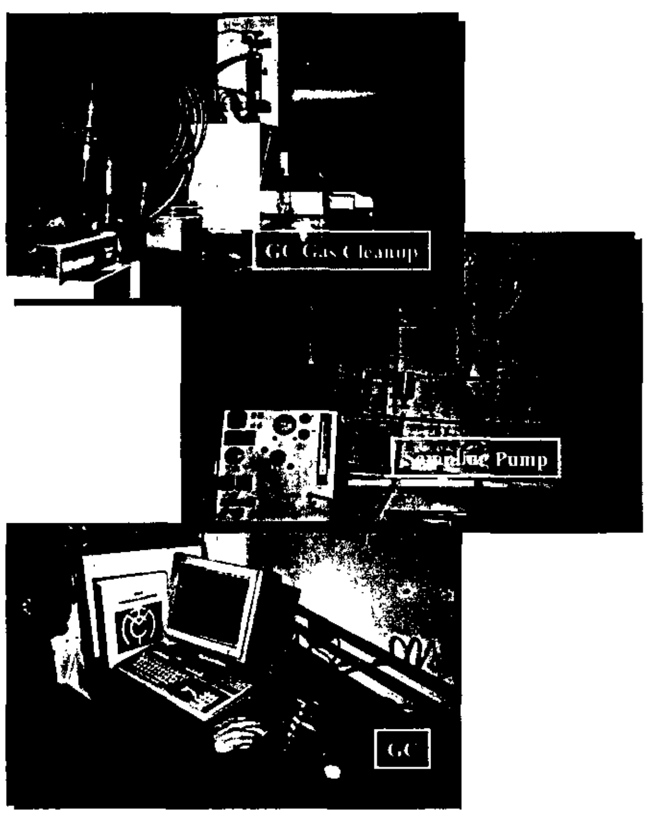



**FIGURE 4-1: GAS CHROMATOGRAPH**

The gas sample is then passed through the dry gas metering pump (middle of Figure 4-1).

Condensate rate was normally determined by measuring the amount of liquid collected per liter of dry gas as measured by a rotameter and dry gas meter. During the PDU tests, however, the amount of water condensed was calculated to achieve a hydrogen balance. This approach is sometimes used because the rotameter and dry gas meter occasionally stick, thereby indicating much lower gas rates than actual.

Samples of the coal feedstock, cyclone products, and bed solids were collected and sent to a qualified independent laboratory for ultimate analysis. The condensate was sent to an independent laboratory for analysis of volatile organics (VOC's), semi-volatile organics (SVOC's), biological oxygen demand (BOD), and chemical oxygen demand (COD).

### 4.4 Analyses of Feedstocks and Products

Table 4-2 provides the coal and solid product analyses for each of the three temperatures evaluated. This data is used to evaluate performance and mass balance closure for the three tests. (Please see Section 4.6.2).

**Table 4-2: Coal and Solid Product Analyses**

| **Solids Analyses** | | | | |
|---|---|---|---|---|
| | Wt%, dry | | | |
| Component | Coal | Product | | |
| | | 1000F | 1100F | 1200F |
| C | 72.00% | 55.86% | 46.64% | 89.17% |
| H | 4.87% | 0.00% | 0.00% | 0.00% |
| N | 1.08% | 0.78% | 0.80% | 1.03% |
| S | 0.38% | 0.35% | 0.07% | 0.04% |
| Ash | 6.05% | 43.01% | 52.49% | 9.76% |
| O | 15.62% | 0.00% | 0.00% | 0.00% |
| | As Received Basis | | | |
| HHV, Btu/lb | 8894 | | | |
| Fixed Carbon | 37.24 | | | |
| Volatile Matter | 31.76 | | | |
| Moisture | 26.56 | | | |

Table 4-3 presents the gas analyses for the three tests, and Table 4-4 presents the corresponding condensate analyses. Nitrogen was used as a tie-in element to determine the gas composition reported in Table 4-3. The condensate data furnished in Table 4-4 are the actual raw data reported by the Laboratory. The major constituent or the remainder of the condensate is water.

**Table 4-3: Gas Analyses**

| Gas Analysis (Nitrogen & Moisture Free) | Vol% | | |
|---|---|---|---|
| | 1000°F | 1100°F | 1200°F |
| Hydrogen | 37.21 | 43.98% | 53.93% |
| Oxygen | | | |
| Nitrogen | 0.00 | 0.00% | 0.00% |
| Methane | 19.14 | 15.85% | 9.40% |
| Carbon Monoxide | 3.89 | 4.944% | 5.54% |
| Carbon Dioxide | 32.90 | 30.15% | 28.96% |
| Ethylene | 2.64 | 2.33% | 1.10% |
| Ethane | 2.75 | 1.72% | 0.61% |
| Acetylene | 0.00 | 0.01% | 0.00% |
| Hydrogen Sulfide | 0.32 | 0.22% | 0.13% |
| Propylene | 1.15 | 0.79% | 0.32% |
| Propane | 0.00 | 0.00% | 0.00% |

**Table 4-4: Condensate Analyses**

| Condensate Analysis | | | | |
|---|---|---|---|---|
| | 1000F | 1100F | 1200F | |
| SVOC | | | | |
| Aniline | 7.2 | 7.1 | 8.3 | mg/L |
| Phenol | 800 | 800 | 800 | mg/L |
| 2-Methylphenol | 290 | 300 | 280 | mg/L |
| 4-Methylphenol, 3-Methylphenol | 900 | 900 | 860 | mg/L |
| 2,4-Dimethylphenol | 110 | 120 | 110 | mg/L |
| Naphthalene | 1.6 | 1.4 | 2.1 | mg/L |
| Acenaphthylene | <0.1 | <0.1 | 0.48 | mg/L |
| Phenanthrene | <0.1 | <0.1 | 0.22 | mg/L |
| Anthracene | <0.1 | <0.1 | 0.13 | mg/L |
| Fluoranthene | <0.1 | 0.11 | <0.1 | mg/L |
| Pyrene | <0.1 | 0.12 | <0.1 | mg/L |
| Bis(2-ethylhexyl)phthalate | 0.28 | 3.4 | 3.4 | mg/L |
| | | | | |

**Table 4-4: Condensate Analyses (continued)**

| VOC | | | | |
|---|---|---|---|---|
| Acetone | 490 | 200 | 290 | mg/kg |
| 2-Butanone | 140 | 110 | 63 | mg/kg |
| Benzene | 18 | 21 | 17 | mg/kg |
| Toluene | 14 | 13 | 10 | mg/kg |
| m,p-Xylene | 3.1 | 2.6 | 2.1 | mg/kg |
| o-Xylene | 1.8 | 1.4 | 1.2 | mg/kg |
| Styrene | 2 | 1.6 | 1.7 | mg/kg |
| Naphthalene | 1.4 | <1.2 | 2.4 | mg/kg |
| | | | | |
| BOD | 13 | 12 | 9.3 | g/L |
| COD | 20 | 20 | 16 | g/L |
| Chloride | 0.15 | 0.21 | 0.14 | g/L |
| Sulfur, total | <0.050 | <0.050 | <0.050 | % |
| | | | | |

## 4.5 Data Analysis Methodology

Mass balances were developed for each of the three PDU tests. The balance was developed using the measured amounts of coal fed, cyclone product collected, and starting and final bed weights along with the corresponding chemical analyses. The mass of each constituent (carbon, hydrogen, nitrogen, sulfur, oxygen, and ash) that was fed during the test or was present in the bed at the beginning of the test was determined simply by multiplying the total amount of material (coal and starting bed) by the chemical analysis. Similarly, the amount of each constituent leaving the reformer or remaining in the reformer at the end of the test was determined using the weights and analyses of the cyclone catch and the final bed. The amount of char in the final bed was determined by subtracting the amount of each constituent in the starting bed from that in the final bed. The amount of char was added to the amount of collected cyclone product to determine the amount of solid product generated during each test.

The amount of gas produced was determined by nitrogen balance. The amount of nitrogen used as instrument purge was measured. Using the amount of nitrogen in the dry product gas as determined by the on-line gas chromatograph and the quantity of nitrogen fed, the total amount of dry product gas was calculated to yield a nitrogen balance. Since the rotameter and dry gas meter readings were not stable, the amount of condensate per volume of dry gas was calculated to yield a hydrogen balance.

The energy balance could not be experimentally determined because the heat loss from the small PDU equipment is orders of magnitude greater than the load required for processing. The difference in heat required to maintain temperature with or without feed could not be measured. This is not a significant problem since the heat of reaction can be accurately calculated by thermodynamic principles based on the heat of combustion (or heat of formation) of the products and reactants; all of which are known.

## 4.6 Data Summary

### 4.6.1 Qualification Test

A total of 6 test campaigns were conducted for the Qualification Test. The different configurations and conditions tested were:

SERIES 1: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, no flue gas recycle

- bed temperature of up to 1,100 F
- natural gas firing rate of up to 14 MMBtu/h

SERIES 2: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,100 F
- natural gas firing rate of up to 22 MMBtu/h

SERIES 3: Long shield tube (24 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,200 F
- natural gas firing rate of up to 22 MMBtu/h

SERIES 4: Short shield tube (3 inch straight tube length), air fluidized bed, natural gas firing, with and without flue gas recycle

- bed temperature of up to 1,350 F
- natural gas firing rate of up to 23 MMBtu/h

SERIES 5: Short shield tube (3 inch straight tube length), water bath, natural gas firing, without flue gas recycle

- bath temperature of 212 F
    - natural gas firing rate of up to 16 MMBtu/h

SERIES 6: Short shield tube (3 inch straight tube length), water bath, syn gas firing, without flue gas recycle

- bath temperature of 212 F
    - syn gas firing rate of up to 11 MMBtu/h

The test measurements and data collection were rather extensive. Data trends are presented in Appendix C. The ensuing discussion targets a specific set of parameters and refers to a 24-h snapshot during operation with the clock starting at 4 AM (0400 h in the attached charts). The test results are presented in Figures 4-2 through 4-15. Data was obtained for both the up and down ramp of the pulse combustor firing rate. During this run, the pulse combustor tripped twice due to air compressor failure. The combustor firing was interlocked with bed fluidization air flow and disruption of this air flow closed the gas solenoid valves. The test was resumed when the air compressor problem was resolved. A bank of five air compressors were used and two different units failed during this test causing the two interruptions.

**FIGURE 4-2: FIRING RATE**

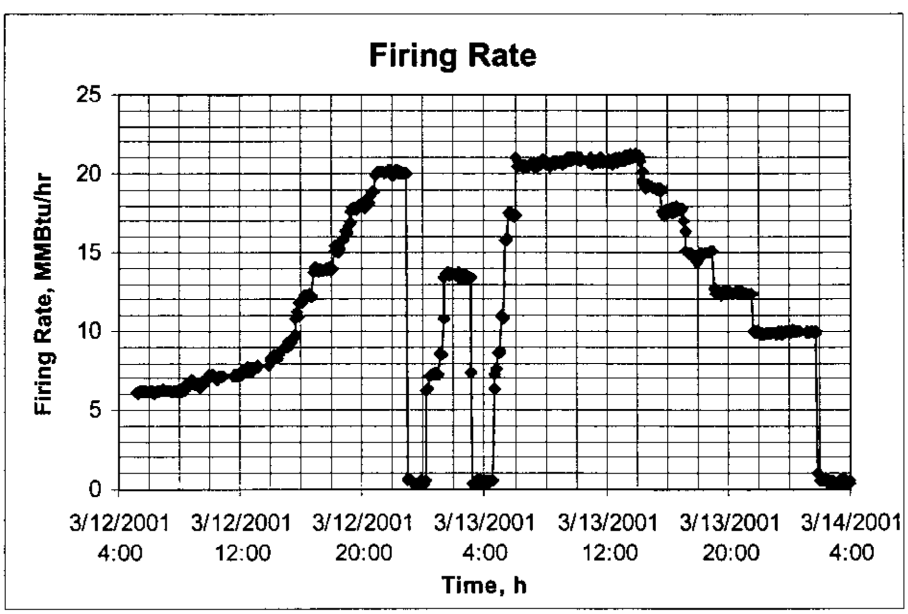


Figure 4-2 indicates the variation in pulse combustor firing rate with time. Natural gas firing rate was ramped up to about 21 MMBtu/h and held steady for about 10 hours. The pulse combustor operation was robust with strong pulsations and air suction with self-aspiration increasing significantly with firing rate.

The dynamic pressure in the combustion chamber was monitored during the test through a HP spectrum analyzer. The pulsation frequency was generally on the order of 58 Hz. The sound pressure level varied from 165 dB (~1.5 psi peak to peak pressure fluctuation) at ~6 MMBtu/h firing rate to about 173dB (~4 psi peak to peak pressure fluctuation) at ~20 MMBtu/h firing rate.

Figure 4-3 depicts the average dense fluid bed temperature. The thermal response of the bed to pulsed heating is quite rapid with bed heatup rates varying between 50 and 200°F per hour. The nominal bed temperature during the run was on the order of 1,000°F, while the peak temperature reached was 1,100°F. Water injection into the bed was started above 1,050°F bed temperature to regulate the bed temperature.

**FIGURE 4-3: Average Bed Temperature**

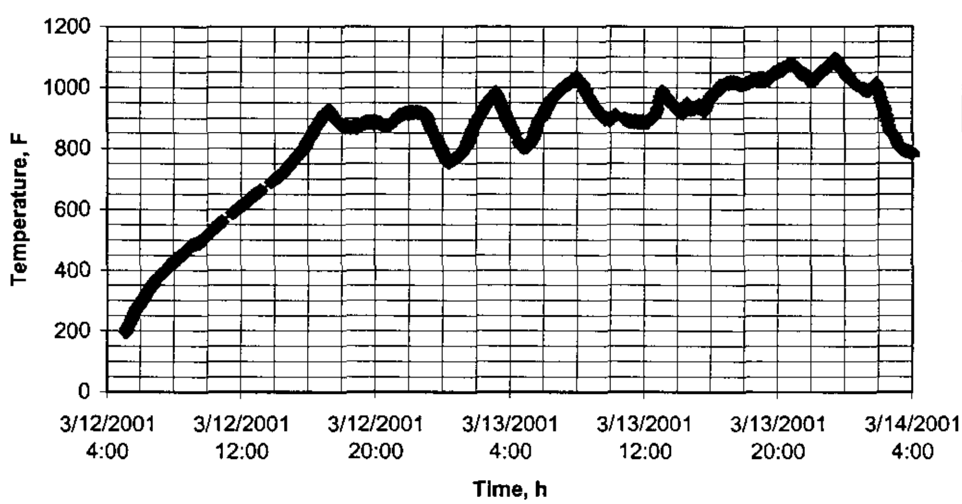
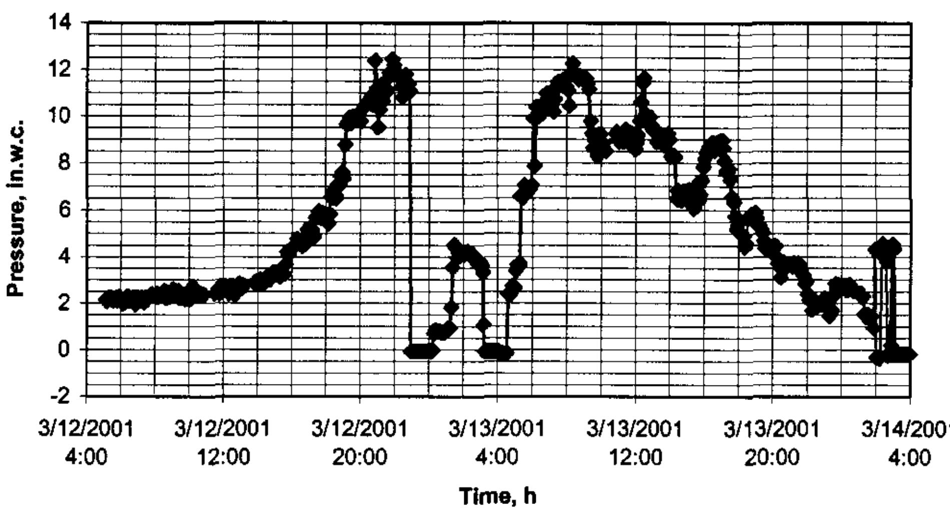


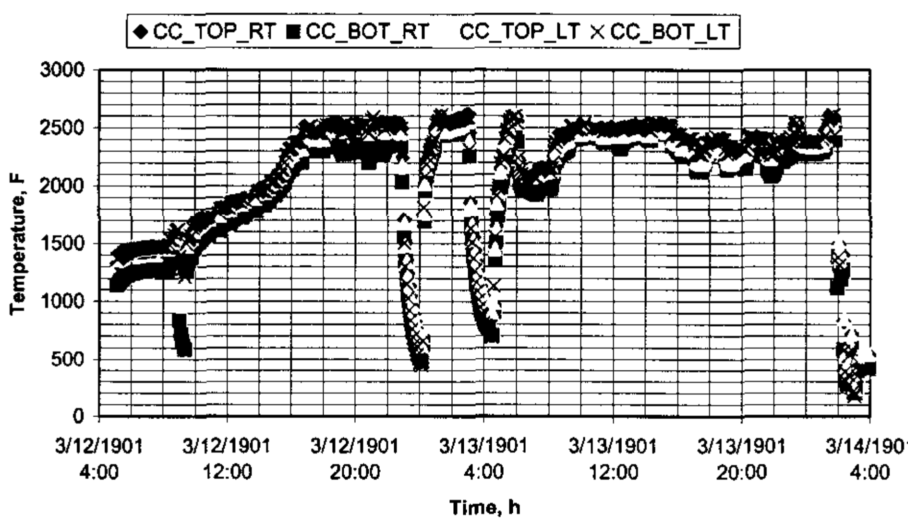

Figure 4-4 shows the static pressure in the air plenum of the pulse combustor. Due to self-aspiration, the demand on static pressure is rather low and is less than 12 inches $H_2O$ at ~21 MMBtu/h firing rate.

FIGURE 4-4: Plenum Pressure




The temperatures registered by four different thermocouples in the pulse combustion chamber are shown in Figure 4-5. The chamber temperature averaged about 2,400°F.

FIGURE 4-5: Combustion Chamber Temperatures




The composition of the flue gas from the combustor was monitored by a continuous emissions monitoring system calibrated and operated by personnel from TRC Environmental Corporation of Connecticut. Figure 4-6 through 4-11 provide the data on a dry basis during this run. The $O_2$ concentration is in the 4 to 10 % range during stable firing of the combustor (see Figure 4-6). This corresponds to between 20 and 80% excess air operation. The O2 concentration was relatively high without flue gas recycle. The high excess air operation was necessary to modulate the combustion chamber temperature. The NOx emissions were relatively high due to the high O2 concentration. With flue gas recycle, the O2 as well as NOx values reduced significantly. The $NO_X$ concentration was in the 10 to 30 ppmv range (see Figure 4-7).

**FIGURE 4-6: O2 Concentration in Flue Gas**

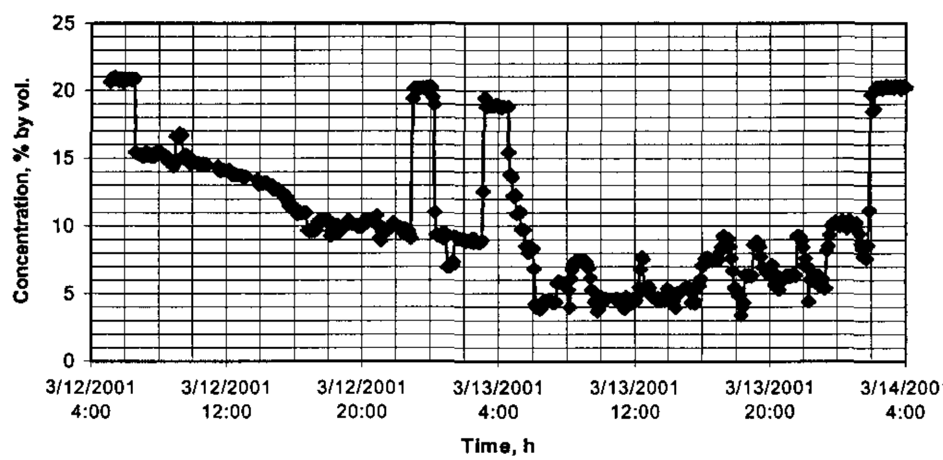
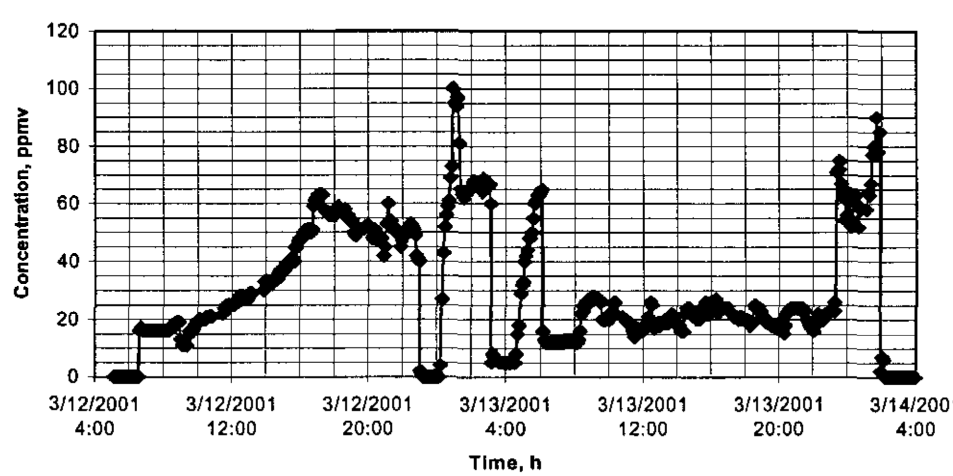



**FIGURE 4-7: NOx Concentration in Flue Gas**



The CO concentration ranged from 100 to 400 ppmv during stable firing of the combustor (see Figure 4-8). The flow and temperature profiles needed to be established and be stable for the combustion to achieve combustion completion. The THC (total hydrocarbons) emissions are generally low (<20 ppmv) except during transients (see Figure 4-9) indicating high combustion efficiency. Figure 4-10 indicates the measured $SO_2$ concentration. As is to be expected, the level is very low and stems from the trace amount of mercaptans in natural gas. The $CO_2$ concentration ranges between 7 and 10% during stable firing (see Figure 4-11), and this is consistent with combustion calculations.

**FIGURE 4-8: CO Concentration in Flue Gas**

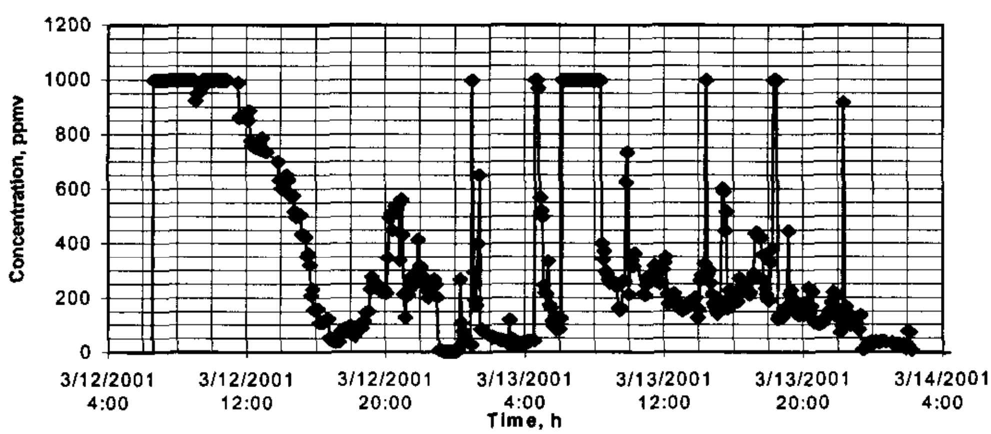



**FIGURE 4-9: THC Concentration, ppm**

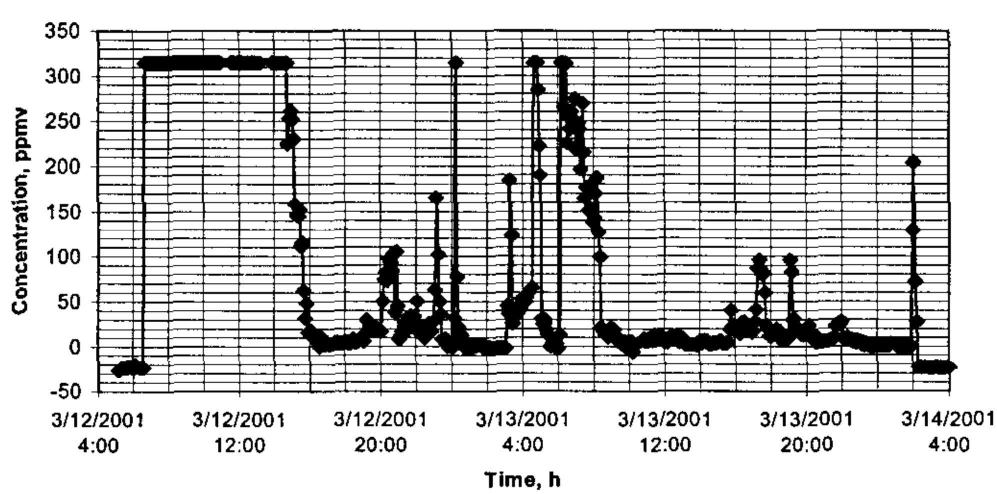


FIGURE 4-10: SO2 Concentration in Flue Gas

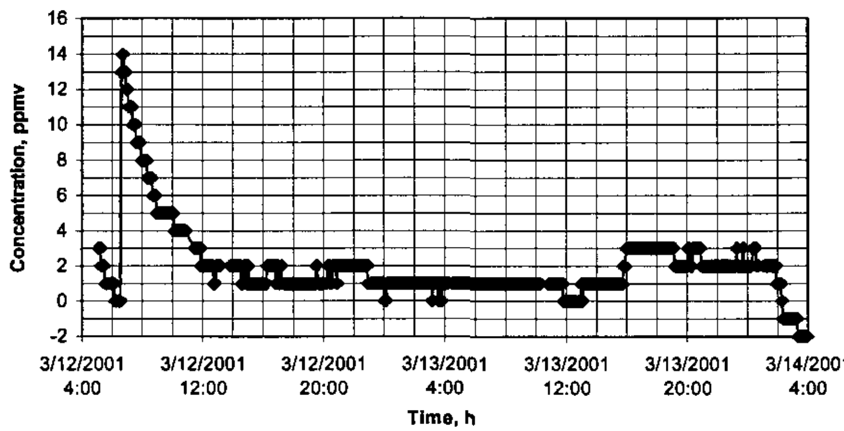



FIGURE 4-11: C02 Concentration in Flue Gas

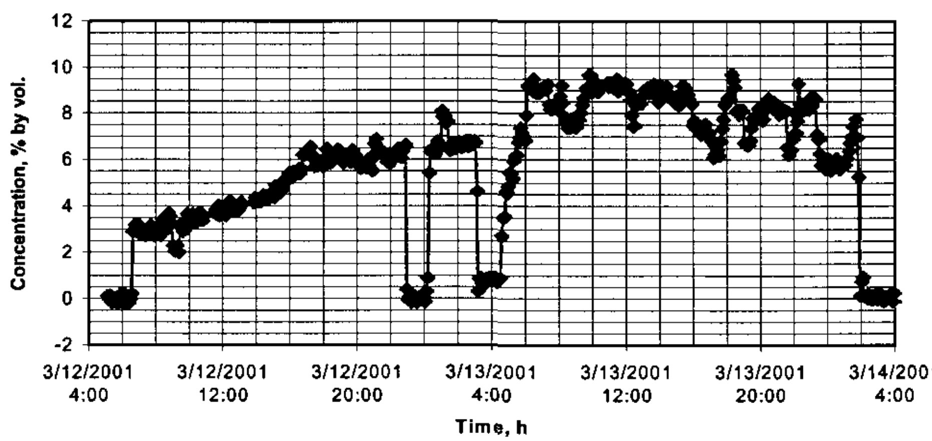



Table 4-5 provides a data summary for test campaigns 2 and 3 long shield tubes. In the flue gas recycle column, 0 denotes no recycle and 1 denotes flue gas recycle. Table 4-6 indicates the measured flue gas composition for the different tests. Table 4-7 presents the calculated results. The spreadsheet used for data analysis and the source code or macros put together are included in the Appendix. These results indicate that high combustion efficiency (99.9+ %) and low emissions including $NO_X$ below 30 ppmv @ 3% $O_2$ can be obtained with flue gas recycle.

## LONG SHIELD TUBE
## TEST CAMPAIGNS 2 AND 3

| ΞST NO. | DATE | TIME | MAIN GAS FIRING RATE MMBTU/H | FUEL DILUTION AIR | FLUE GAS RECYCLE | FRESH AIR TEMP. F | RECYCLE TEMP. F | FAN INLET TEMP. F |
|---|---|---|---|---|---|---|---|---|
| ·1 | 3/2/2001 | 1:49 | 17.29 | YES | 0 | 43 | | 43 |
| ·2 | 3/2/2001 | 3:45 | 20.61 | YES | 0 | 42 | | 42 |
| ·3 | 3/2/2001 | 10:19 | 20.49 | YES | 1 | 43 | 397 | 128 |
| ·4 | 3/2/2001 | 12:44 | 17.50 | NO | 0 | 55 | | 55 |
| ·1 | 3/12/2001 | 14:55 | 8.93 | NO | 0 | 55 | | 55 |
| 2 | 3/12/2001 | 15:58 | 11.79 | NO | 0 | 54 | | 54 |
| ·3 | 3/12/2001 | 17:43 | 13.88 | NO | 0 | 50 | | 50 |
| ·4 | 3/12/2001 | 19:58 | 18.10 | NO | 0 | 46 | | 46 |
| ·5 | 3/12/2001 | 21:57 | 19.90 | NO | 0 | 44 | | 44 |
| ·6 | 3/13/2001 | 2:04 | 13.69 | NO | 0 | 42 | | 42 |
| ·7 | 3/13/2001 | 13:30 | 21.20 | NO | 1 | 43 | 461 | 147 |
| ·8 | 3/13/2001 | 15:00 | 19.24 | NO | 1 | 43 | 377 | 125 |
| ·9 | 3/13/2001 | 15:55 | 17.77 | NO | 1 | 43 | 385 | 125 |
| ·10 | 3/13/2001 | 18:04 | 14.44 | NO | 1 | 43 | 461 | 160 |
| ·11 | 3/13/2001 | 20:24 | 12.37 | NO | 1 | 43 | 332 | 116 |
| ·12 | 3/15/2001 | 22:49 | 9.87 | NO | 1 | 43 | 352 | 127 |
| ·13 | 3/15/2001 | 16:26 | 3.30 | NO | 0 | 43 | | 49 |
| ·14 | 3/15/2001 | 17:01 | 5.04 | NO | 0 | 43 | | 47 |
| ·15 | 3/15/2001 | 17:51 | 5.99 | NO | 0 | 43 | | 44 |
| ·16 | 3/15/2001 | 19:36 | 17.61 | NO | 0 | 43 | | 45 |
| ·17 | 3/15/2001 | 20:36 | 20.88 | NO | 0 | 43 | | 44 |
| ·18 | 3/15/2001 | 21:41 | 14.98 | NO | 0 | 43 | | 44 |
| ·19 | 3/15/2001 | 22:31 | 17.58 | YES | 0 | 43 | | 44 |

## ARY - TEST OPERATIONS

| INLET P. | AIR PLENUM PRESSURE INCH H20 | AIR PLENUM TEMP. F | PULSE COMBUST. CHAMBER TEMP. F | DECOUPLER TEMP. F | MUFFLER TEMP. F | BED TEMP. F | BED HEIGHT INCH | SUPERFICIAL FLUIDIZATION VELOCITY FT/S |
|---|---|---|---|---|---|---|---|---|
| | 8.84 | 153 | 2,476 | 1236 | 700 | 983 | 83.2 | 0.54 |
| | 14.07 | 165 | 2,426 | 1250 | 700 | 835 | 99.8 | 0.77 |
| | 8.59 | 366 | 2,445 | 1187 | 700 | 863 | 91.0 | 1.17 |
| | 5.32 | 370 | 2,691 | 1232 | 700 | 932 | 87.7 | 1.31 |
| | 3.31 | 119 | 1,925 | 1045 | 630 | 747 | 118.8 | 1.20 |
| | 4.37 | 174 | 2,101 | 1154 | 701 | 822 | 123.4 | 1.28 |
| | 5.63 | 234 | 2,454 | 1246 | 700 | 893 | 139.0 | 1.38 |
| | 9.80 | 278 | 2,441 | 1246 | 694 | 888 | 119.7 | 1.27 |
| | 12.19 | 255 | 2,483 | 1234 | 700 | 916 | 134.0 | 1.14 |
| | 4.09 | 301 | 2,487 | 1152 | 700 | 890 | 136.4 | 1.08 |
| | 9.19 | 463 | 2,448 | 1279 | 700 | 959 | 94.2 | 1.23 |
| | 6.71 | 430 | 2,494 | 1228 | 700 | 932 | 89.8 | 1.19 |
| | 7.28 | 386 | 2,489 | 1226 | 700 | 962 | 98.7 | 1.22 |
| | 5.05 | 433 | 2,202 | 1241 | 700 | 1012 | 82.4 | 1.27 |
| | 3.62 | 354 | 2,266 | 1247 | 700 | 1065 | 84.4 | 1.23 |
| | 2.02 | 357 | 2,346 | 1217 | 700 | 1060 | 91.9 | 1.03 |
| | 0.45 | 73 | 1,494 | 644 | 512 | 608 | 82.4 | 0.52 |
| | 0.37 | 80 | 2,032 | 733 | 576 | 635 | 78.9 | 0.52 |
| | 0.72 | 93 | 2,229 | 856 | 670 | 715 | 79.0 | 0.63 |
| | 7.93 | 318 | 2,552 | 1256 | 701 | 997 | 85.8 | 1.47 |
| | 11.11 | 267 | 2,545 | 1356 | 701 | 1063 | 99.0 | 1.49 |
| | 6.42 | 262 | 2,432 | 1260 | 694 | 1017 | 99.7 | 1.67 |
| | 8.76 | 202 | 2,537 | 1275 | 700 | 987 | 86.9 | 1.64 |

## TABLE 4-6: FLUE GAS ANALYSIS

**LONG SHIELD TUBE**
**TEST CAMPAIGNS 2 AND 3**

| TEST NO. | DATE | TIME | FLUE GAS ANALYSIS | | | | |
|---|---|---|---|---|---|---|---|
| | | | O2 % | CO2 % | CO PPMV | NOX PPMV | THC PPMV |
| 2-1 | 3/2/2001 | 1:49 | 10.23 | 5.59 | 428 | 58 | 44 |
| 2-2 | 3/2/2001 | 3:45 | 10.56 | 5.40 | 499 | 56 | 62 |
| 2-3 | 3/2/2001 | 10:19 | 5.07 | 8.64 | 228 | 24 | 49 |
| 2-4 | 3/2/2001 | 12:44 | 7.45 | 7.50 | 53 | 90 | 2 |
| 3-1 | 3/12/2001 | 14:55 | 12.70 | 4.44 | 505 | 37 | 261 |
| 3-2 | 3/12/2001 | 15:58 | 11.32 | 5.42 | 152 | 48 | 15 |
| 3-3 | 3/12/2001 | 17:43 | 10.41 | 5.91 | 87 | 56 | 4 |
| 3-4 | 3/12/2001 | 19:58 | 9.95 | 6.01 | 219 | 52 | 19 |
| 3-5 | 3/12/2001 | 21:57 | 10.10 | 5.81 | 316 | 47 | 26 |
| 3-6 | 3/13/2001 | 2:04 | 8.91 | 6.74 | 59 | 66 | 1 |
| 3-7 | 3/13/2001 | 13:30 | 4.55 | 9.06 | 177 | 19 | 2 |
| 3-8 | 3/13/2001 | 15:00 | 5.37 | 8.64 | 150 | 21 | 5 |
| 3-9 | 3/13/2001 | 15:55 | 6.07 | 8.40 | 216 | 22 | 24 |
| 3-10 | 3/13/2001 | 18:04 | 5.28 | 8.67 | 189 | 20 | 12 |
| 3-11 | 3/13/2001 | 20:24 | 5.83 | 8.20 | 143 | 18 | 9 |
| 3-12 | 3/15/2001 | 22:49 | 5.95 | 8.45 | 103 | 22 | 4 |
| 3-13 | 3/15/2001 | 16:26 | 13.25 | 4.10 | 971 | 19 | 315 |
| 3-14 | 3/15/2001 | 17:01 | 9.49 | 6.20 | 69 | 47 | 30 |
| 3-15 | 3/15/2001 | 17:51 | 9.71 | 6.05 | 36 | 55 | 10 |
| 3-16 | 3/15/2001 | 19:36 | 8.58 | 6.79 | 69 | 57 | 2 |
| 3-17 | 3/15/2001 | 20:36 | 9.10 | 6.71 | 81 | 53 | 16 |
| 3-18 | 3/15/2001 | 21:41 | 9.95 | 6.15 | 209 | 44 | 1 |
| 3-19 | 3/15/2001 | 22:31 | 9.58 | 6.15 | 225 | 52 | 9 |

## TABLE 4-7: CALCULATED RESULTS

| TEST NO. | DATE | TIME | COMBUSTION EFFICIENCY | HEAT TRANSFERRED, % | EX |
|---|---|---|---|---|---|
| 2-1 | 3/2/2001 | 1:49 | 99.70% | 54.5% | |
| 2-2 | 3/2/2001 | 3:45 | 99.62% | 56.6% | |
| 2-3 | 3/2/2001 | 10:19 | 99.85% | 46.6% | |
| 2-4 | 3/2/2001 | 12:44 | 99.98% | 45.9% | |
| 3-1 | 3/12/2001 | 14:55 | 99.10% | 55.3% | |
| 3-2 | 3/12/2001 | 15:58 | 99.88% | 54.2% | |
| 3-3 | 3/12/2001 | 17:43 | 99.95% | 54.8% | |
| 3-4 | 3/12/2001 | 19:58 | 99.86% | 53.8% | |
| 3-5 | 3/12/2001 | 21:57 | 99.79% | 54.0% | |
| 3-6 | 3/13/2001 | 2:04 | 99.97% | 46.7% | |
| 3-7 | 3/13/2001 | 13:30 | 99.93% | 48.8% | |
| 3-8 | 3/13/2001 | 15:00 | 99.93% | 49.0% | |
| 3-9 | 3/13/2001 | 15:55 | 99.88% | 50.1% | |
| 3-10 | 3/13/2001 | 18:04 | 99.91% | 49.3% | |
| 3-11 | 3/13/2001 | 20:24 | 99.93% | 50.5% | |
| 3-12 | 3/13/2001 | 22:49 | 99.95% | 49.7% | |
| 3-13 | 3/15/2001 | 16:26 | 98.57% | 37.1% | |
| 3-14 | 3/15/2001 | 17:01 | 99.92% | 31.5% | |
| 3-15 | 3/15/2001 | 17:51 | 99.97% | 36.6% | |
| 3-16 | 3/15/2001 | 19:36 | 99.97% | 49.8% | |
| 3-17 | 3/15/2001 | 20:36 | 99.94% | 55.3% | |
| 3-18 | 3/15/2001 | 21:41 | 99.89% | 54.1% | |
| 3-19 | 3/15/2001 | 22:31 | 99.87% | 53.7% | |

| EXCESS AIR | CORRECTED TO 3% O2 | | | RECYCLE FLUE GAS TO AIR MASS RATIO |
|---|---|---|---|---|
| | CO, PPMV | $NO_x$, PPMV | THC, PPMV | |
| 80.7% | 715 | 97 | 74 | |
| 87.1% | 860 | 97 | 107 | |
| 25.4% | 258 | 27 | 55 | 22% |
| 45.5% | 70 | 120 | 3 | |
| 126.0% | 1,095 | 80 | 566 | |
| 98.0% | 283 | 89 | 28 | |
| 82.6% | 148 | 95 | 7 | |
| 76.8% | 357 | 85 | 31 | |
| 79.6% | 522 | 78 | 43 | |
| 60.7% | 88 | 98 | 1 | |
| 21.9% | 194 | 21 | 2 | 23% |
| 27.4% | 173 | 24 | 6 | 23% |
| 32.6% | 260 | 27 | 29 | 23% |
| 25.0% | 216 | 23 | 14 | 28% |
| 28.2% | 170 | 21 | 11 | 24% |
| 27.2% | 123 | 26 | 5 | 27% |
| 124.6% | 2,225 | 44 | 731 | |
| 57.0% | 108 | 74 | 47 | |
| 62.8% | 57 | 88 | 16 | |
| 58.1% | 100 | 83 | 3 | |
| 65.5% | 122 | 80 | 24 | |
| 75.7% | 340 | 72 | 2 | |
| 71.2% | 355 | 82 | 14 | |

Figure 4-12 shows the variation in combustion efficiency with natural gas firing rate for the pulse combustor. The combustion efficiency improves with firing rate. This is attributed to enhanced fuel air mixing, more robust pulsations and higher flow field temperatures with an increase in firing rate.

FIGURE 4-12: VARIATION OF COMBUSTION EFFICIENCY WITH GAS FIRING RATE

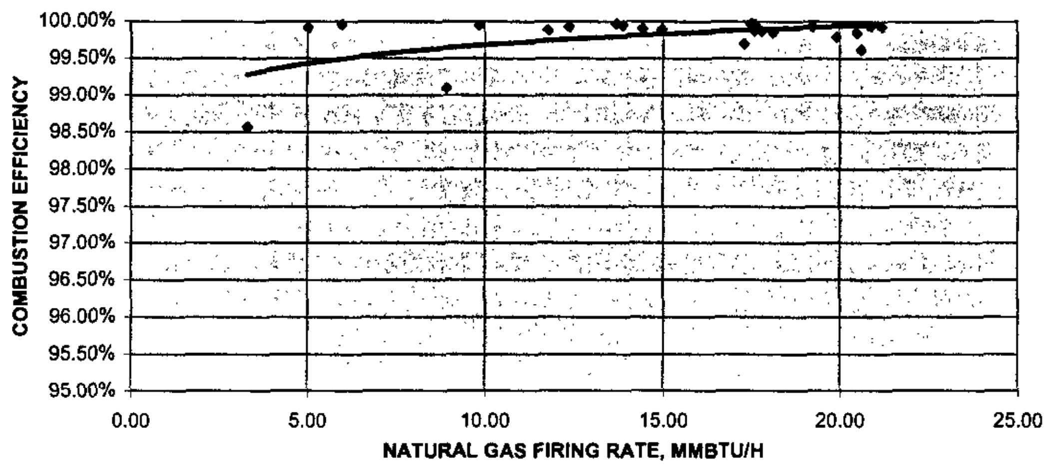



Figure 4-13 indicates the variation in combustion efficiency with excess air. The highest efficiency (i.e. very low CO and hydrocarbon concentrations in the exiting flue gas) is obtained for excess air in the 40 to 60% range. The excess air requirement is rather high (higher than the 15-25% norm in typical burners) due to the low (1,000-1,200°F) resonance tube temperatures. The coal and black liquor steam reforming applications demand low resonance tube temperatures and this in turn requires reasonable $O_2$ concentration or partial pressure in the flue gas to achieve high combustion efficiency.

FIGURE 4-13: VARIATION IN COMBUSTION EFFICIENCY WITH EXCESS AIR

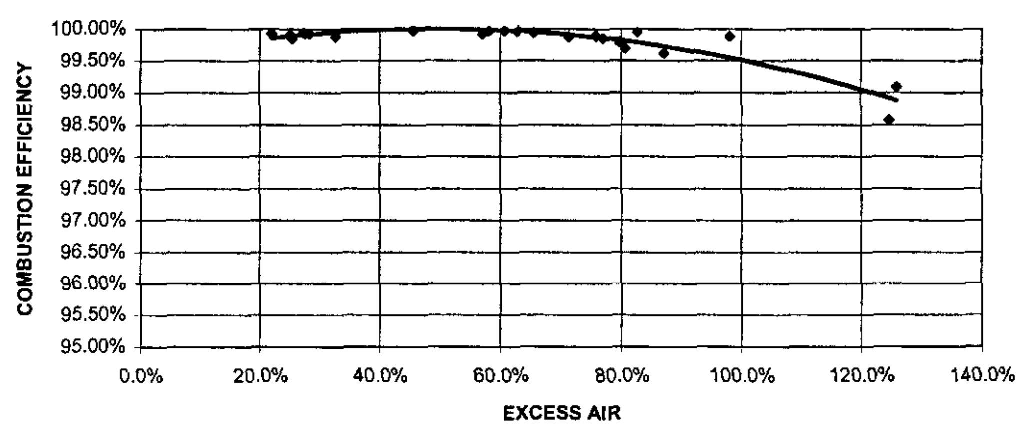


Figure 4-14 depicts the effect of fluidized bed temperature on combustion efficiency. As expected, the combustion efficiency increases with bed temperature. This stems from the concurrent increase in resonance tube temperature and in turn the reaction rate of fuel fragments.

**FIGURE 4-14: EFFECT OF BED TEMPERATURE ON COMBUSTION EFFICIENCY**

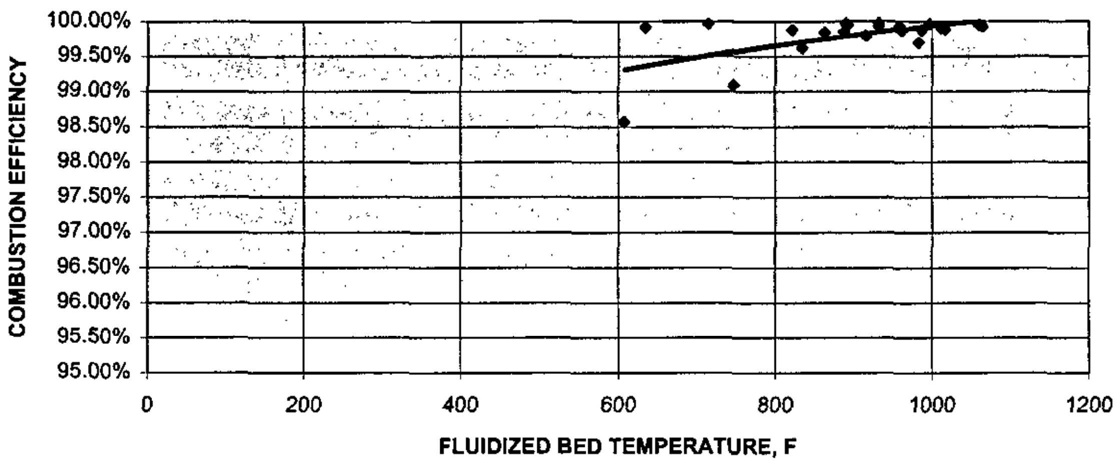
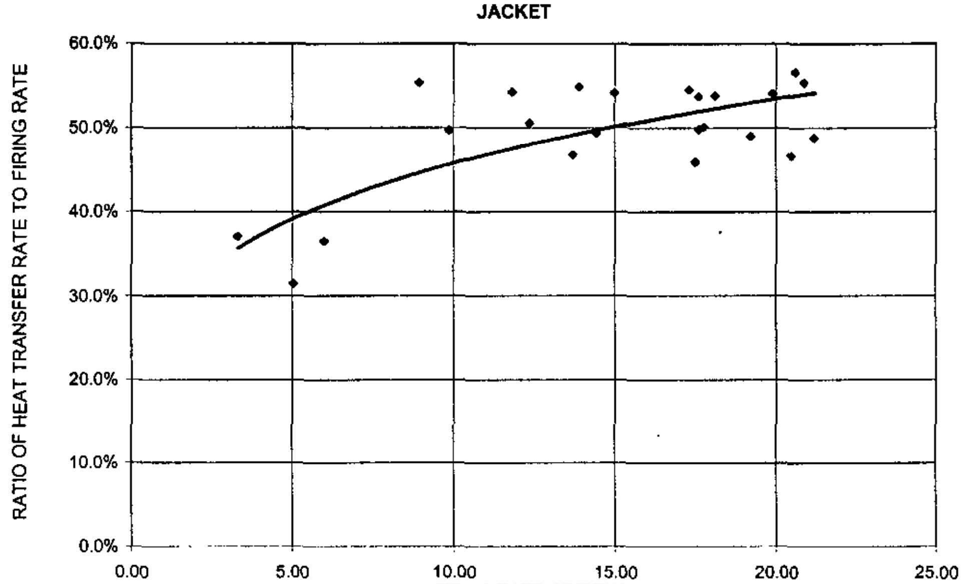



Figure 4-15 exhibits the variations in heat transfer rate to the fluidized bed and the water jacket with firing rate. The ratio of heat transfer rate to the firing rate increases with pulse combustor firing rate. This is attributed to enhancement in pulsations and reduction in excess air with an increase in firing rate.

**FIGURE 4-15: HEAT TRANSFERRED TO THE FLUIDIZED BED AND THE WATER JACKET**



### 4.6.2. PDU Tests

The mass balance summaries for each test are presented in Tables 4-8 through 4-10.

**Table 4-8: Mass Balance for 1000F Test**

| | | **Stream No** | **1** | **2** | **3** | **4** | **5** |
|---|---|---|---|---|---|---|---|
| | | | **Coal** | **Steam** | **Nitrogen Purge** | **Product Gas** | **Char** |
| **Component** | **Units** | **Formula** | | | | | |
| Hydrogen | Lb/Hr | H2 | | | | 0.569 | |
| Nitrogen | Lb/Hr | N2 | | | 19.518 | 19.691 | |
| Methane | Lb/Hr | CH4 | | | | 2.324 | |
| Carbon Monoxide | Lb/Hr | CO | | | | 0.825 | |
| Carbon Dioxide | Lb/Hr | CO2 | | | | 10.955 | |
| Ethylene | Lb/Hr | C2H4 | | | | 0.561 | |
| Ethane | Lb/Hr | C2H6 | | | | 0.625 | |
| Acetylene | Lb/Hr | C2H2 | | | | 0.000 | |
| Hydrogen Sulfide | Lb/Hr | H2S | | | | 0.083 | |
| Propylene | Lb/Hr | C3H6 | | | | 0.365 | |
| Propane | Lb/Hr | C3H8 | | | | 0.000 | |
| Steam | Lb/Hr | H2O | | 23.361 | | 40.941 | |
| Coal | Lb/Hr | | 52.000 | | | | |
| Char | Lb/Hr | | | | | | 30.645 |
| Condensables | Lb/Hr | | | | | 0.331 | |
| | | | | | | | |
| TOTAL MASS | Lb/Hr | -- | 52.000 | 23.361 | 19.518 | 77.270 | 30.645 |

**Table 4-9: Mass Balance for 1100°F Test**

| | | Stream No | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|---|
| | | | Coal | Steam | Nitrogen Purge | Product Gas | Char |
| Component | Units | Formula | | | | | |
| Hydrogen | Lb/Hr | H2 | | | | 0.634 | |
| Nitrogen | Lb/Hr | N2 | | | 13.308 | 13.458 | |
| Methane | Lb/Hr | CH4 | | | | 1.814 | |
| Carbon Monoxide | Lb/Hr | CO | | | | 0.988 | |
| Carbon Dioxide | Lb/Hr | CO2 | | | | 9.462 | |
| Ethylene | Lb/Hr | C2H4 | | | | 0.466 | |
| Ethane | Lb/Hr | C2H6 | | | | 0.369 | |
| Acetylene | Lb/Hr | C2H2 | | | | 0.002 | |
| Hydrogen Sulfide | Lb/Hr | H2S | | | | 0.054 | |
| Propylene | Lb/Hr | C3H6 | | | | 0.238 | |
| Propane | Lb/Hr | C3H8 | | | | 0.000 | |
| Steam | Lb/Hr | H2O | | 27.117 | | 41.963 | |
| Coal | Lb/Hr | | 45.000 | | | | |
| Char | Lb/Hr | | | | | | 25.826 |
| Condensables | Lb/Hr | | | | | 0.268 | |
| | | | | | | | |
| TOTAL MASS | Lb/Hr | -- | 45.000 | 27.117 | 13.308 | 69.716 | 25.826 |

**Table 4-10: Mass Balance for 1200°F Test**

| | | Stream No | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|---|
| | | | Coal | Steam | Nitrogen | Product | Char |
| | | | | | Purge | Gas | |
| **Component** | **Units** | **Formula** | | | | | |
| Hydrogen | Lb/Hr | H2 | | | | 2.301 | |
| Nitrogen | Lb/Hr | N2 | | | 18.187 | 18.326 | |
| Methane | Lb/Hr | CH4 | | | | 3.186 | |
| Carbon Monoxide | Lb/Hr | CO | | | | 3.275 | |
| Carbon Dioxide | Lb/Hr | CO2 | | | | 26.926 | |
| Ethylene | Lb/Hr | C2H4 | | | | 0.652 | |
| Ethane | Lb/Hr | C2H6 | | | | 0.390 | |
| Acetylene | Lb/Hr | C2H2 | | | | 0.004 | |
| Hydrogen Sulfide | Lb/Hr | H2S | | | | 0.097 | |
| Propylene | Lb/Hr | C3H6 | | | | 0.281 | |
| Propane | Lb/Hr | C3H8 | | | | 0.000 | |
| Steam | Lb/Hr | H2O | | 18.618 | | 7.549 | |
| Coal | Lb/Hr | | 32.000 | | | | |
| Char | Lb/Hr | | | | | | 12.263 |
| Condensables | Lb/Hr | | | | | 0.266 | |
| | | | | | | | |
| TOTAL MASS | Lb/Hr | -- | 32.000 | 18.618 | 18.187 | 63.252 | 12.263 |

The closure for each constituent is presented in tables 4-11 through 4-13.

**Table 4-11: Mass balance closure for 1000F Test.**

| ELEMENTAL BALANCES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| **IN** | C | H | N | S | Ash | O | | TOTAL |
| Coal | 27.498 | 3.410 | 0.411 | 0.146 | 2.309 | 18.227 | | 52.000 |
| Steam | | 2.619 | | | | 20.742 | | 23.361 |
| Purge | | | 19.518 | | | | | 19.518 |
| TOTAL | 27.498 | 6.029 | 19.929 | 0.146 | 2.309 | 38.970 | | 94.879 |
| | | | | | | | | |
| **OUT** | | | | | | | | |
| Char | 16.983 | 0.000 | 0.238 | 0.106 | 13.075 | 0.000 | | 30.402 |
| Cond Organics | 0.254 | 0.02 | | | | 0.056 | | 0.331 |
| Product Gas | 6.375 | 6.007 | 19.691 | 0.078 | 0.000 | 44.788 | | 76.939 |
| TOTAL | 23.611 | 6.029 | 19.929 | 0.184 | 13.075 | 44.844 | | 107.672 |
| | | | | | | | | |
| **Closure** | **0.859** | **1.000** | **1.000** | **1.262** | **5.663** | **1.151** | | **1.135** |

**Table 4-12: Mass balance closure for 1100°F Test**

| ELEMENTAL BALANCES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| **IN** | C | H | N | S | Ash | O | | TOTAL |
| Coal | 23.796 | 2.951 | 0.356 | 0.126 | 1.998 | 15.774 | | 45.000 |
| Steam | | 3.040 | | | | 24.077 | | 27.117 |
| Purge | | | 13.308 | | | | | 13.308 |
| TOTAL | 23.796 | 5.991 | 13.663 | 0.126 | 1.998 | 39.851 | | 85.424 |
| | | | | | | | | |
| **OUT** | | | | | | | | |
| Char | 11.962 | 0.000 | 0.205 | 0.018 | 13.464 | 0.000 | | 25.649 |
| Cond Organics | 0.206 | 0.02 | | | | 0.046 | | 0.268 |
| Product Gas | 5.262 | 5.973 | 13.458 | 0.051 | 0.000 | 44.703 | | 69.448 |
| TOTAL | 17.430 | 5.991 | 13.663 | 0.069 | 13.464 | 44.748 | | 95.365 |
| | | | | | | | | |
| **Closure** | **0.732** | **1.000** | **1.000** | **0.547** | **6.739** | **1.123** | | **1.116** |

**Table 4-13: Mass balance closure for 1200°F Test**

| ELEMENTAL BALANCES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| **IN** | C | H | N | S | Ash | O | | TOTAL |
| Coal | 16.922 | 2.098 | 0.253 | 0.090 | 1.421 | 11.217 | | 32.000 |
| Steam | | 2.087 | | | | 16.531 | | 18.618 |
| Purge | | | 18.187 | | | | | 18.187 |
| TOTAL | 16.922 | 4.185 | 18.440 | 0.090 | 1.421 | 27.748 | | 68.805 |
| | | | | | | | | |
| **OUT** | | | | | | | | |
| Char | 10.630 | 0.000 | 0.123 | 0.005 | 1.164 | 0.000 | | 11.921 |
| Cond Organics | 0.203 | 0.02 | | | | 0.045 | | 0.266 |
| Product Gas | 12.250 | 4.168 | 18.326 | 0.091 | 0.000 | 28.152 | | 62.987 |
| TOTAL | 23.084 | 4.185 | 18.448 | 0.096 | 1.164 | 28.197 | | 75.174 |
| | | | | | | | | |
| **Closure** | **1.364** | **1.000** | **1.000** | **1.071** | **0.819** | **1.016** | | **1.093** |

The elemental closures are very good for such a small-scale experiment. The ash closure is off more than other constituents due to measuring small differences in large numbers: the starting bed of sand is reported as ash and weighs more than all the ash fed during the combined tests. Nitrogen and hydrogen closure is forced by the calculation procedure described earlier.

Tables 4-14 and 4-15 present a summary of the Volatile Organic Compounds (VOC) and Semi-Volatile Organic Compounds (SVOC) collected in the gas condensate. The gas condensates were collected with an EPA method 5 sampling train utilizing ice-water bath impingers. Since the full-scale, commercial cold gas cleanup equipment does not achieve ice-water bath temperatures and the commercial steam reformer will have reduced freeboard heat losses and higher gas residence times, these captured organic condensate quantities are considered the upper limit or high and worst case values.

**Table 4-14: VOC in the Product Gas Stream**

| VOC | mg/kg of dry feed | | |
|---|---|---|---|
| | 1,000°F | 1,100°F | 1,200°F |
| Acetone | 434.05 | 104.83 | 39.09 |
| 2-Butanone | 124.02 | 57.66 | 8.49 |
| Benzene | 15.94 | 11.01 | 2.29 |
| Toluene | 12.40 | 6.81 | 1.35 |
| Xylenes | 4.34 | 2.10 | 0.44 |
| Styrene | 1.77 | 0.84 | 0.23 |
| Naphthalene | 1.24 | 0.00 | 0.32 |
| **TOTAL VOC** | 593.77 | 183.25 | 52.22 |

**Table 4-15: SVOC in the Product Gas Stream**

| SVOC | mg/kg of dry feed | | |
|---|---|---|---|
| | 1,000°F | 1,100°F | 1,200°F |
| Phenols | 1860.23 | 1111.24 | 276.33 |
| Naphthalene | 1.42 | 0.73 | 0.28 |
| Aniline | 6.38 | 3.72 | 1.12 |
| Others | 0.25 | 1.90 | 0.57 |
| **TOTAL SVOC** | 1868.28 | 1117.60 | 278.30 |

## 4.7 Operability and Reliability

There were no operability and reliability issues associated with the PDU testing.

# 5.0 TECHNICAL PERFORMANCE

## 5.1 Effects of Operating Variables on Results

The amount of each constituent reporting to each product for all three tests is presented in Tables 5-1 through 5-3.

**Table 5-1: Product Distribution for 1000°F Test**

| Normalized Product Yields Percent Reported | | | |
|---|---|---|---|
| | To Solids | To Gas | To Condensate |
| C | 72.44% | 27.19% | 0.37% |
| H | 0.00% | 99.88% | 0.12% |
| N | 1.19% | 98.81% | 0.00% |
| S | 57.45% | 42.55% | 0.00% |
| Ash | 100.00% | 0.00% | 0.00% |
| O | 0.00% | 99.96% | 0.04% |

**Table 5-2: Product Distribution for 1100°F Test**

| Normalized Product Yields Percent Reported | | | |
|---|---|---|---|
| | To Solids | To Gas | To Condensate |
| C | 69.13% | 30.41% | 0.46% |
| H | 0.00% | 99.89% | 0.11% |
| N | 1.50% | 98.50% | 0.00% |
| S | 25.86% | 74.14% | 0.00% |
| Ash | 100.00% | 0.00% | 0.00% |
| O | 0.00% | 99.96% | 0.04% |

**Table 5-3: Product Distribution for 1200°F Test**

| Normalized Product Yields Percent Reported | | | |
|---|---|---|---|
| | To Solids | To Gas | To Condensate |
| C | 46.43% | 53.51% | 0.06% |
| H | 0.00% | 99.97% | 0.03% |
| N | 0.66% | 99.34% | 0.00% |
| S | 5.25% | 94.75% | 0.00% |
| Ash | 100.00% | 0.00% | 0.00% |
| O | 0.00% | 99.99% | 0.01% |

In these tables, the data presented earlier was normalized, that is, each constituent is adjusted to provide a 100% closure. This helps to eliminate the effect of mass balance accuracy variations. As would be expected, the amount of carbon and the amount of sulfur reported to char decreases with increasing temperature. The condensate appears to receive a lower portion of carbon as temperature increases as would be expected. In order to maximize char production, operation at 1000 or 1100°F would be preferred. Char suitable for Direct Iron Production is generated at either temperature.

## 6.0 ENVIRONMENTAL PERFORMANCE

A process condensate is the only waste stream generated in this process since the gas is used as fuel and the char is the primary product. Stack emission from combustion of the gas is discussed below.

Biological Oxygen Demand (BOD) is the primary concern with the effluent. Generally, if this is reduced, the individual organic species contributing to the BOD will be reduced. BOD as a function of operating temperature is presented in Table 6-1.

**Table 6-1: Effluent BOD**

| EFFLUENT BOD | | | |
|---|---|---|---|
| | 1000F | 1100F | 1200F |
| BOD, lb/Ton dry coal | 13.98 | 15.27 | 3.04 |
| BOD, lb/Ton dry char | 19.30 | 22.09 | 6.55 |

There is very little difference in effluent quality between the two lower operating temperatures, as one would expect considering there is little difference in char and gas yields between these two conditions. At the higher temperature, gasification appears to begin and the liquid organics that contribute to BOD are being destroyed somewhat.

A facility producing 20 tons of char per hour and operating at 1000 F would produce a raw effluent stream containing approximately five tons of BOD. This raw effluent could not be discharged directly into a stream; however, conventional aerobic digestion technology would adequately treat the stream for discharge. A treatment facility would be required even for the higher temperature operating condition. Although this facility would be smaller than that required for low temperature operation, the cost savings associated with treatment would no doubt be more than offset with reduced product yield.

## 7.0 ECONOMICS

### 7.1 Estimated Process Capital Costs

The projected process capital cost provided in this report for a commercial configuration plant is based upon projections only. The information is to be regarded as extrapolations (Scaling Factors) and budget quality engineering estimates. The cost is, of necessity, not based on actual data from a full-scale demonstration project for mild gasification of coal.

Table 7-1 presents the major equipment list for a commercial configuration plant for mild gasification of sub-bituminous coal for the Northshore Mining Company. This configuration is the most likely near term commercial plant since Northshore is still in need of such a plant. The projections are made based on a budget estimate study performed by Industra (dated July 17, 1997) which was adjusted for inflation and other considerations (scale-up from similar systems for spent liquor recovery providing new cost data since July 17, 1997).

The plant is based on a reactor with five 253-tube heaters having a nominal coal processing (mild gasification) capacity of 40 US tons per hour. For the purpose of operating cost calculations (Section 6.0), the plant was assumed to be operating at 36 US tons per hour.

Coal is fed into the steam reformer utilizing a weigh feeder and a water-cooled injection screw feeder. Ash and unreacted char are removed from the reformer via lockhoppers and a cooling conveyor.

A cold gas cleanup train is used to process the raw reformate gas from the steam reformer.

Cyclones provide fundamental particulate control, followed by a venturi scrubber to remove any remaining entrained particulate. A gas cooler with acidic pH control provides the dual purpose of cooling the gas (condensing the steam) as well as ammonia removal.

The $H_2S$ absorber contacts the relatively cool gas (125°F) with caustic to remove the sulfur as a NaHS solution. The sulfide solution will be sold to a local pulp mill as chemical makeup for the cooking process.

Finally, the reformate gas is clean and acceptable for burning as a fuel in the pulse heaters as well as in boilers for steam generation.

Table 7-1 presents the major equipment list for the commercial configuration mild gasification project. The table also indicates the items that are within the normal scope of supply from ThermoChem, and the items that are obtained by the clients' engineers via multiple-vendor quotes.

Table 7-2 presents the major equipment costs.

The plant total installed cost is shown in Table 7-3. The table presents, in addition to the Major Equipment Costs, other costs associated with the field erection of the plant.

## TABLE 7-1: MAJOR EQUIPMENT LIST

| Item No. | Item Name | Quantity | | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | Operating | Spare | | | | |
| 1 | Coal-Handling System: | | | 40 ton/h (wet) | | | |
| 2 | Bucket Elevator | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 3 | Conveyor | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 4 | Weigh Feeder | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 5 | Feed Screw | 1 | | 40 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 6 | Storage Bin | 1 | | 40 ton/h | Cylindrical with 70° Cone Bottom | Carbon Steel | Multiple Vendor Quotes |
| 7 | Reactor w/steam distributor | 1 | | 36.1 ton/h (wet) | Refractory-lined Rectangular Vessel | Carbon Steel | ThermoChem |
| 8 | Pulsed Heater w/Plenum & Aerovalves | 5 | | 253-tube 6.0 MMBtu/h each | PulseEnhanced™ | 321 SS | ThermoChem |
| 9 | Pulsed Heater Combustion Air Fan | 2 | | 9400 acfm @ 28" WC | 75 HP Blower | Carbon Steel | ThermoChem |
| 10 | Char-Handling System: | | | 13.5 ton/h (dry) | | | |
| 11 | Lock Hopper | 1 | | 1,000 lbs. char | Standard | Carbon Steel | ThermoChem |
| 12 | Cooling Conveyor | 1 | | 13.5 ton/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 13 | Char-Slurry Mixing Tank | 1 | | 27 ton | Cylindrical with Conical Bottom | Carbon Steel | Multiple Vendor Quotes |
| 14 | Char-Mixing Tank Pumps | 2 | | 66 gpm, 7.5 hp each | Slurry-Handling | Carbon Steel | Multiple Vendor Quotes |
| 15 | Char-Mixing Tank Agitator | 1 | | 5 hp each | Medium Turbulence | Carbon Steel | Multiple Vendor Quotes |
| 16 | First Stage Cyclone | 4 | | 5000 acfm | 95% Removal | 321 SS | ThermoChem |
| 17 | Second Stage Cyclone | 4 | | 5000 acfm | 99.5% Removal | Refractory-lined Carbon Steel | ThermoChem |
| 18 | Heat Recovery Steam Generator # 1 (HRSG1) | 1 | | 26250 lb/h @ 150 psig | Unfired | Carbon Steel | ThermoChem |

**TABLE 7-1 (continued): MAJOR EQUIPMENT LIST**

| Item No. | Item Name | Quantity | | Unit Capacity | Design Characteristics | Material of Construction | Vendor |
|---|---|---|---|---|---|---|---|
| | | Operating | Spare | | | | |
| 19 | HRSG1 Recirculation Pump | 1 | 1 | 60 gpm | 25 hp High Temp/ Pressure Service | Carbon Steel | ThermoChem |
| 20 | Venturi Scrubber | 1 | | 20000 acfm | S. Steel Throat | Carbon Steel Body | ThermoChem |
| 21 | Venturi Scrubber Pump | 1 | 1 | 160 gpm, 10 hp each | Slurry-Handling | Carbon Steel | ThermoChem |
| 22 | Gas Cooler Column w/pH control | 1 | | 20000 ACFM | 5.5' D X 19' H Packed | Carbon Steel | ThermoChem |
| 23 | Gas Cooler Tank | 1 | | 5000 | Cylindrical w/Dished Bottom | Carbon Steel | ThermoChem |
| 24 | Gas Cooler Heat Exchanger | 1 | | 2 MM Btu/h | Plate Heat Exchanger | Carbon Steel | ThermoChem |
| 25 | Gas Cooler Recirculation Pump | 1 | 1 | 760 gpm, 20 hp each | Centrifugal | Carbon Steel | ThermoChem |
| 26 | $H_2S$ Absorber | 1 | | 20000 acfm | 5.5' D X 24' H Packed | Carbon Steel | ThermoChem |
| 27 | $H_2S$ Absorber Recirculation Pump | 1 | 1 | 110 gpm, 2 hp each | Centrifugal | Carbon Steel | ThermoChem |
| 28 | Superheater | 1 | | 4.2 MM Btu/h | Standard | 304 SS | ThermoChem |
| 29 | Heat Recovery Steam Generator 2 (HRSG2) | 1 | | 39,000 lb/h @ 150 psig | Fired with off-gas or Natural gas | Carbon Steel | Multiple Vendor Quotes |
| 30 | Air Heater | 1 | | 9 MM Btu/h | Standard | Carbon Steel | Multiple Vendor Quotes |
| 31 | Stack | 1 | | 20000 acfm | 83' H | Carbon Steel | Multiple Vendor Quotes |
| 32 | SS Duct Work | 1 lot | | 6700 sq. ft. | 3/16" Different Sizes | 304 SS | Multiple Vendor Quotes |
| 33 | Carbon Steel Duct Work | 1 lot | | 3300 sq. ft. | 3/16" Different Sizes | Carbon Steel | Multiple Vendor Quotes |

TABLE 7-2: MAJOR EQUI

| Item No. | Item Name | F.O.B. Cost/ Unit | Sales Tax | Freight Cost | Installing Cost | Total Cost Ea. |
|---|---|---|---|---|---|---|
| 1 | Coal-Handling Systems: | | | | | |
| 2 | Bucket Elevator | 100,000 | | 2,000 | 5,000 | 107,000 |
| 3 | Conveyor | 155,000 | | 3,100 | 5,000 | 163,100 |
| 4 | Weigh Feeder | 50,000 | | 1,000 | 2,500 | 53,500 |
| 5 | Feed Screw | 75,000 | | 1,500 | 2,500 | 79,000 |
| 6 | Storage Bin | 300,000 | | 6,000 | 12,500 | 318,500 |
| 7 | Reactor w/Steam Distributor | 401,000 | | 8,020 | 110,000 | 519,020 |
| 8 | Pulsed Heater w/ Plenum & Aerovalves | 507,800 | | 10,156 | 10,000 | 527,956 |
| 9 | Pulsed Heater Combustion Air Fan | 12,500 | | 250 | 6,790 | 19,540 |
| 10 | Char-Handling System: | | | | | |
| 11 | Lock Hopper | 2,000 | | 40 | 1,500 | 3,540 |
| 12 | Cooling Conveyor | 50,000 | | 1,000 | 2,500 | 53,500 |
| 13 | Char-Mixing Tank | 5,000 | | 100 | 950 | 6,050 |
| 14 | Char-Mixing Tank Pumps | 2,000 | | 40 | 2,500 | 4,540 |
| 15 | Char-Mixing Tank Agitator | 2,000 | | 40 | 1,000 | 3,040 |
| 16 | First Stage Cyclone | 36,250 | | 725 | 2,500 | 39,475 |
| 17 | Second Stage Cyclone | 37,500 | | 750 | 2,500 | 40,750 |
| 18 | Heat Recovery Steam Generator # 1 | 300,000 | | 6,000 | 14,900 | 320,900 |
| 19 | Recirculation Pump | 3,500 | | 70 | 3,100 | 6,670 |
| 20 | Venturi Scrubber w/Throat | 13,000 | | 260 | 2,300 | 15,560 |
| 21 | Venturi Scrubber Pump | 4,500 | | 90 | 4,100 | 8,690 |
| 22 | Gas Cooler Column w/pH control[1] | 12,000 | | 240 | 2,500 | 14,740 |

[1] Ammonia removal

## AJOR EQUIPMENT COSTS

| Total Cost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|
| | | Equipment | Freight | Installation | |
| | | | | | |
| 107,000 | 1.0 | 100,000 | 2,000 | 5,000 | 107,000 |
| 163,100 | 1.0 | 155,000 | 3,100 | 5,000 | 163,100 |
| 53,500 | 1.0 | 50,000 | 1,000 | 2,500 | 53,500 |
| 79,000 | 1.0 | 75,000 | 1,500 | 2,500 | 79,000 |
| 318,500 | 1.0 | 300,000 | 6,000 | 12,500 | 318,500 |
| 519,020 | 1.0 | 401,000 | 8,020 | 110,000 | 519,020 |
| 527,956 | 5.0 | 2,539,000 | 50,780 | 50,000 | 2,639,780 |
| 19,540 | 2.0 | 25,000 | 500 | 13,580 | 39,080 |
| | | | | | |
| 3,540 | 1.0 | 2,000 | 40 | 1,500 | 3,540 |
| 53,500 | 1.0 | 50,000 | 1,000 | 2,500 | 53,500 |
| 6,050 | 1.0 | 5,000 | 100 | 950 | 6,050 |
| 4,540 | 2.0 | 4,000 | 80 | 5,000 | 9,080 |
| 3,040 | 1.0 | 2,000 | 40 | 1,000 | 3,040 |
| 39,475 | 4.0 | 145,000 | 2,900 | 10,000 | 157,900 |
| 40,750 | 4.0 | 150,000 | 3,000 | 10,000 | 163,000 |
| 320,900 | 1.0 | 300,000 | 6,000 | 14,900 | 320,900 |
| 6,670 | 2.0 | 7,000 | 140 | 6,200 | 13,340 |
| 15,560 | 1.0 | 13,000 | 260 | 2,300 | 15,560 |
| 8,690 | 2.0 | 9,000 | 180 | 8,200 | 17,380 |
| 14,740 | 1.0 | 12,000 | 240 | 2,500 | 14,740 |

TABLE 7-2(continued): MAJOR EC

| Item No. | Item Name | F.O.B. Cost/Unit | Sales Tax | Freight Cost | Installing Cost | Total Cost Ea. |
|---|---|---|---|---|---|---|
| 23 | Gas Cooler Tank | 2,500 | | 50 | 1,000 | 3,550 |
| 24 | Gas Cooler Heat Exchanger | 4,000 | | 80 | 1,000 | 5,080 |
| 25 | Gas Cooler Recirculation Pump | 11,000 | | 220 | 3,100 | 14,320 |
| 26 | $H_2S$ Absorber (sulfur removal) | 13,000 | | 260 | 2,500 | 15,760 |
| 27 | $H_2S$ Absorber Recirculation Pump | 2,500 | | 50 | 3,100 | 5,650 |
| 28 | Superheater | 35,000 | | 700 | 1,500 | 37,200 |
| 29 | Heat Recovery Steam Generator 2 | 708,000 | | 14,160 | 24,800 | 746,960 |
| 30 | Air Heater | 150,000 | | 3,000 | 2,500 | 155,500 |
| 31 | Stack | 25,000 | | 500 | 2,500 | 28,000 |
| 32 | St. Steel Duct Work (one lot) | | | | 188,000 | 188,000 |
| 33 | C. Steel Duct Work (one lot) | | | | 188,00 | 188,000 |
| 34 | Equipment Paint (one lot) | | | | 21,000 | 21 000 |
| 35 | Insulation Including Duct (one lot) | | | | 81,000 | 81.000 |
| 36 | Miscellaneous Materials | | | | 209,000 | 209,000 |

**Major Equipment Cost Totals**

ed): MAJOR EQUIPMENT COSTS

| Total Cost Ea. | No. of Units | Totals | | | Total Cost |
|---|---|---|---|---|---|
| | | Equipment | Freight | Installation | |
| 3,550 | 1.0 | 2,500 | 50 | 1,000 | 3,550 |
| 5,080 | 1.0 | 4,000 | 80 | 1,000 | 5,080 |
| 14,320 | 2.0 | 22,000 | 440 | 6,200 | 28,640 |
| 15,760 | 1.0 | 13,000 | 260 | 2,500 | 15,760 |
| 5,650 | 2.0 | 5,000 | 100 | 6,200 | 11,300 |
| 37,200 | 1.0 | 35,000 | 700 | 1,500 | 37,200 |
| 746,960 | 1.0 | 708,000 | 14,160 | 24,800 | 746,960 |
| 155,500 | 1.0 | 150,000 | 3,000 | 2,500 | 155,500 |
| 28,000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| 188,000 | 1.0 | 25,000 | 500 | 2,500 | 28,000 |
| 188,000 | 1.0 | 0 | 0 | 188,000 | 188,000 |
| 21,000 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| 81,000 | 1.0 | 0 | 0 | 21,000 | 21,000 |
| 209,000 | 1.0 | 0 | 0 | 209,000 | 209,000 |
| | | **5,333,500** | **106,670** | **755,830** | **6,196,000** |

## TABLE 7-3: PROJECT TOTAL INSTALLED COST

| Item No. | Item Description | Unit Cost Equipment/ Material | Unit Cost Installation/ Subcontract | Item Total Cost | Remarks |
|---|---|---|---|---|---|
| | **Direct Costs:** | | | | |
| 1 | Major Equipment | $5,440,170 | $755,830 | $6,196,000 | |
| 2 | Piping | $1,170,000 | $1,013,000 | $2,183,000 | |
| 3 | Electrical | $170,000 | $250,000 | $420,000 | |
| 4 | Instrumentation & Control | $670,000 | $530,000 | $1,200,000 | |
| 5 | Site Preparation | $20,000 | $130,000 | $150,000 | |
| 6 | Civil/Structure | $25,000 | $100,000 | $125,000 | |
| 7 | Building | $600,000 | $660,000 | $1,260,000 | |
| 8 | Operation & Startup Spares | | | $700,000 | Includes one Pulse Heater |
| 9 | 10% Escalation | | | $1,250,000 | 3-yrs since 98 Estimate |
| 10 | Land | | | $500,000 | |
| 11 | Preliminary Expenses/Project Fees | | | $2,250,000 | |
| 12 | Insurance and Permits | | | $2,100,000 | |
| 13 | Warranty & Licensing Fees | | | $1,800,000 | |
| 14 | 10% Execution Contingency | | | $1,950,000 | |
| | | | | | |
| **Direct Cost Total** | | **$8,095,170** | **$3,438,830** | **$22,084,000** | |
| | | | | | |
| **Indirect Cost:** | | | | | |
| 15 | 8% Detailed Engineering | | | $1,500,000 | |
| 16 | Project and Construction Management | | | $1,700,000 | |
| 17 | Commissioning and Start-Up | | | $650,000 | Includes Training Support |
| 18 | General & Administrative Expenses | | | $1,500,000 | |
| 19 | General Contingency | | | $750,000 | |
| **Indirect Cost Total** | | | | **$6,100,000** | |
| **PROJECT TOTAL INSTALLED COST** | | | | **$28,184,000** | |

## 8.0 COMMERCIALIZATION POTENTIAL AND PLANS

### 8.1. Market Analysis

Under the CCT demonstration program, key components of the technology will be demonstrated at full commercial-scale to test commercial applicability, ability to achieve economies-of-scale and ability to use alternative coal feedstocks. While the demonstration will test the MTCI technology for its char reductant generation potential, the technology can also produce several other products for other market applications.

#### 8.1.1. Applicability of the Technology

The CCT demonstration project carried out by MTCI is to qualify a single 253-tube pulse combustor heater bundle. The heater bundle is the heart of a commercial-scale steam reformer system that has broad commercial applications including:

- black liquor processing and chemical recovery;
- hazardous, low-level mixed waste volume reduction and destruction;
- coal processing for:
  - the production of hydrogen for fuel cell power generation and other uses,
  - production of gas and char for the steel industry,
  - production of solid Clean Air Act compliance fuels,
  - production of syngas that can be used as a feedstock for the chemicals industry, for power generation, for the production of high quality liquid products, and for other purposes,
- coal-pond waste and coal rejects processing for overfiring/reburning for utility $NO_X$ control; and
- utilization of a range of other fuels and wastes to produce a variety of value added products.

Recognizing that the CCT Demonstration Program is intended to expand the markets for coal and improve the competitiveness of coal in domestic markets, especially in the electric power market, a preliminary assessment of the most promising coal applications of the MTCI technology was conducted. These applications used mild gasification of coal (via the MTCI technology) to produce: (1) metallurgical coke replacement, (2) compliance coal for existing power plants, and (3) syngas for use as an industrial feedstock and power production.

### 8.1.2 Market Size

#### 8.1.2.1 ...for Metallurgical Coke Replacement

Integrated metallurgical coke production in 1996 was approximately 18.5 million short tons[1]. Although blast furnace metallurgical coke consumption has declined by almost 1.8 million short tons from 1995 (to 16.7 million tons), there remains a shortage of coke from integrated mills of over 4 million tons. As a result of the planned closing of several coke plants, the shortfall has risen by 265,000 tons in 1998 and an additional 900,000 tons in 1999. This will bring the total shortfall to over 5 million, which is expected to be met by domestic merchant coke plants.

Breeze, a lower quality coke, is also utilized in the iron and steel industry. However, in the U.S., less than 1 million short tons of breeze are consumed. In addition, although the large majority of coke is utilized in blast furnaces, some (less than 10%) are consumed in foundries (U.S. Department of Commerce, Manufacturing Consumption of Energy, 1994).

#### 8.1.2.2 ... for Compliance Coal

The acid rain provisions (Title IV) of the Clean Air Act Amendments of 1990 require existing coal-fired power plants to reduce their $SO_2$ emissions in two phases, in 1995 and 2000. To comply with the 1995 requirements, many power plants switched coals to those with a sulfur content that complies with the emissions target (below 2.5 lbs. sulfur/MMBtu); this is also known as "compliance coal." Although many utilities are still assessing options for compliance with the more stringent year 2000 requirements (1.2

lbs. sulfur/MMBtu), it is expected that coal switching to a low sulfur coal will again be the dominant compliance method. Coal switching is a popular compliance choice due to its relatively low cost because a capital investment in flue gas desulfurization (FGD) or other $SO_2$ control technology is not required.

#### 8.1.2.3 Synthesis Gas for Power Production

Synthesis gas can be used instead of natural gas or oil in combustion turbines to produce electric power. At present, three U.S. power plants convert coal to syngas via gasification in the Clean Coal Technology Demonstration program. In addition, several industrial (petrochemical) sites are (will be) using refinery bottoms and petroleum coke as feedstocks to a gasifier to produce electricity and other chemical byproducts. The MTCI technology can also produce synthesis gas from coal for use in combustion turbines to produce electric power.

Several market opportunities exist for the use of the MTCI technology for power production. These include (1) new capacity, (2) replacement capacity, and (3) compliance capacity. Each opportunity is discussed in the following.

At present 95,300 megawatts (MW) of combined cycle and combustion turbines in the power sector are fueled by natural gas. These units generate over 80 billion kilowatt-hours, and consume 2.98 trillion cubic feet of natural gas (approximately 3 Quads).

Natural gas is currently the preferred fuel for new electric generating capacity (peaking/intermediate and baseload). This is because: (1) current fuel costs are relatively low, and they comprise 93% (projected to be reduced to 88% by 2005 with the use of advanced NGCC technologies) of the operational costs for a natural gas combined cycle (NGCC) facility; (2) the capital cost of combined-cycle plants is low and the time to install them is relatively short thereby reducing up front capital costs and producing revenues more quickly than other power options; (3) the efficiency of combined cycle plants is high and improving, and (4) the environmental issues associated with gas use are fewer than most economically viable options.

### 8.1.2.4 Synthesis Gas for industrial Feedstocks

Based upon information obtained from industrial sources, conventional methods for reforming natural gas to synthetic gas are capital intensive. As a result, the cost of synthetic gas derived from natural gas is roughly 1 $^1/_2$ to 3 times the price of natural gas feedstock. Considering that natural gas supplied to industrial users in the states where most of the synthetic gas users are located is \$3-\$4/MMBtu, the synthetic gas prices for industrial feedstocks are on the order of \$4.50-\$12/MMBtu. Where a commercial-scale MTCI steam reformer can produce a syngas having comparable chemical properties within or less than this price range, there may be market opportunities for the technology. The price of syngas produced by the MTCI technology is dependent upon the cost of coal used as its feedstock. To compete with \$4.50/MMBtu conventional syngas, a large MTCI plant would have to use \$23-\$25/MMBtu coal. A small MTCI plant would have to use \$5/MMBtu coal and a 15% IRR to be competitive with \$4.50 syngas. At the upper end of the conventional syngas cost range, the MTCI technology would be competitive no matter what the coal price or the IRR considered.

### 8.1.3 Market Barriers

The U. S. steel industry is currently in an economic downswing. This is probably the single most dramatic barrier to overcome for the DRI and coking applications.

Natural gas pricing will also have a major impact on incentives to proceed with steam reforming projects.

## 8.2. Commercialization Plan

Current plans are to work with a recognized company such as Midrex who has extensive experience and contacts within the steel and related industries. ThermoChem is currently in contact with Midrex discussing areas of mutual interest. Midrex's technical in-house capabilities would provide the new steam reforming process with valuable design and operating experience for the first operating plant.

# APPENDIX A

# Test Plan

# TEST PLAN

Pulse Combustor Design Qualification Test
Cooperative Agreement DE-FC22-92PC92644

September 11, 2000

The principal objectives of the project are to perform qualification testing of a 253-tube pulse heater and to demonstrate its readiness for commercial deployment. Specific objectives include verification and demonstration of:

- Full-scale heater performance, operability, reliability, and availability;
- Steam reformer system performance, operability, reliability, and availability;
- Thermal and gasification efficiency with coal from the process data unit;
- Emissions ($SO_X$, $NO_X$, THC, CO) determination;
- Waste stream (ash and effluent) regulatory compliance from the process data unit; and
- Economic merit of this technology

Tests will be conducted in two separate facilities to develop the data required to commercialize the Steam Reforming technology. Full-scale heater performance will be assessed in the Pulse Combustor Test Facility. Process data, i.e., gas yields and composition; char yields and composition; emissions; and heat requirements will be determined in a Process Data Unit.

## Full-Scale Heater Tests

Performance of a full-scale multiple resonance tube pulse combustor will be determined in the test facility constructed as part of this project. The pulse combustor's role in the reformer is to provide the process heat required. The amount of heat that can be supplied by the pulse combustor will be determined at various operating conditions. Combustor firing rate and excess air levels are the variables to be examined within the combustor. Of course, the amount of heat that can be transferred to the fluidized bed is also dependent upon the conditions within the bed (bed-side heat transfer coefficient) and the tube-to-bed temperature difference. The tube temperatures and bed temperatures will be monitored and used in conjunction with energy balance data to determine the bed-side heat transfer coefficient. Combustor efficiency and emissions will be determined at various firing rates (up to 30 million Btu/hr), excess air levels (20% to 60%), and fluidized bed operating temperatures (1100 $^{o}$F to 1650 $^{o}$F).

The fluidized bed test facility will be filled with sand and fluidized with air. Water will be injected into the bed to impose a heat load, thereby controlling the bed temperature independently of combustor firing rate.

Gas flow and combustion air flow rates will be measured for each test. The pulse combustor flue gas will be analyzed to determine the concentration of oxygen, carbon monoxide, nitrogen oxides, sulfur dioxide, and hydrocarbons. This data will be used to assess combustion efficiency at various firing rates and excess air levels.

The fluidized bed temperture, fluidizing air flow, water flow for bed temperature control, pulse combustor exhaust temperature, resonance tube temperature, combustion air temperature, combustor cooling circuit steam generation, and fluidized bed shell temperatures will be measured for each test. This data will permit calculation of an energy balance and quantification of the amount of heat transferred to the bed and the tube-to-bed heat transfer coefficient.

**Process Data Tests**

It continues to appear that one of the more promising early applications of the technology will be similar to the manufacture of coke; i.e., the production of char for use in direct reduction of iron (DRI). In this application, the char is a direct substitute for metallurgical coke. The purity requirements are easily satisfied by the char produced via mild gasification and the strength requirements for coke used in conventional blast furnace operations are not relevant to the DRI process. This application is the basis for selecting the coal to be tested in the Process Data Unit. The specific coal was selected in conjunction with Northshore Mining for their use as a reductant.

Petroleum coke, which can be used as a DRI reductant has the following specifications:

0.5% Sulfur
90% Fixed Carbon
5-10% Volatiles

A coal-derived char should surpass these specifications in order to be more attractive than petroleum coke. The specifications provided by Northshore mining for the char are:

0.3% Sulfur
85% Fixed Carbon

Volatile content is not important to Northshore; however, in order to achieve the target of 85% fixed carbon, volatile content will necessarily be fairly low.

The optimum coal for testing is Black Thunder subbituminous coal since this coal is currently used by Northshore as fuel and is therefore readily available at the site. The characteristics of this coal are typical of Powder River Basin coals:

| | |
|---|---|
| % Moisture | 24.0 - 33.0 |
| % Carbon | 47.0 - 53.0 |
| % Hydrogen | 3.2 - 3.8 |
| % Nitrogen | 0.82 - 0.84 |
| % Oxygen | 11.1 - 13.4 |
| % Chloride | 0.00 - 0.03 |
| % Sulfur | 0.21 - 0.47 |
| % Ash | 3.2 - 5.6 |

The primary variable will be operating temperature. The goal is to identify the lowest temperature at which satisfactory sulfur and volatile matter content reduction is achieved. This temperature should result in the lowest amount of fixed carbon conversion to gas, thereby increasing product yield. The lower operating temperature also provides a higher tube-to-bed temperature differential which improves heat transfer into the reformer and increases throughput.

Complete mass and energy balances will be performed for each steady state PDU test to verify mass closure and to determine the process heat requirement. The coal feed rate, fluidizing steam rate, and instrument purge (nitrogen) rate are measured for each test. A slip stream of product gas is collected in a Method 5 impinger train and the steam and condensable hydrocarbons are collected for analysis. Fixed gas composition is determined by on-line gas chromatography. Product char will be collected and analyzed for comparison with the targets provided above.

**Data Analysis**

The data obtained will form the basis for designing a facility capable of producing 10 tons per hour of char for use in Direct Reduction of Iron. Data from the PDU will be used to identify feed coal requirements (product yields) and waste stream flows and composition. The combustor test facility data will provide information required to determine the number of heaters that must be used to satisfy the reformer heat load and process emissions data.

This preliminary facility design will be used as the basis for completing an economic assessment of the technology

**253-tube Pulse Heater Test Parameters and Measurements**

Objectives:

- Map out the operational boundary
- Compare performance and temperature profiles with model projections
- Evaluate operability, stability, reliability and safety attributes

Test Parameters:

- Fuel firing rate

- Combustion stoichiometry
- Fuel/air premixing ratio
- Superficial fluidization velocity of the fluidized bed
- Fluidized bed temperature
- Fuel type – natural gas, H2-rich syn gas

Test Measurements:

- Static pressures
  - air plenum
  - fuel supply
  - premix air supply
  - pulse combustion chamber
  - decoupler
  - exhaust muffler inlet
  - fluid bed air inlet plenum
  - at different elevations of the dense fluidized bed and the freeboard
  - cyclone inlet
  - steam drum
  - compressed air flow to the flue gas spray quench atomizer
  - water flow to the flue gas spray quench atomizer
- Dynamic pressure
  - pulse combustion chamber
  - decoupler exit
  - exhaust muffler inlet
  - exhaust muffler exit
- Temperatures
  - air inlet in duct just upstream of air plenum
  - air plenum
  - pulse combustion chamber
  - flue gas in decoupler

- flue gas at decoupler exit/upstream of water spray
- flue gas at exhaust muffler inlet
- resonance tube skin temperature – 4 outer tubes each @ 3 locations along the tube
- gas temperature just upstream of resonance tube exit – at the center of the tube bundle and in 4 outer tubes in the bundle
- fluidized bed – several locations
- tubesheet at pulse combustion chamber/resonance tube interface – 4 locations
- air inlet into fluidized bed
- freeboard – inlet and exit
- steam drum
- cooling water in to pulse combustor tubesheets
- cooling water out from pulse combustor tubesheets

- Flow rates
  - combustion air
  - fuel
  - premix air
  - fluidization air
  - pilot gas
  - pilot air
  - water circulation rate to the pulse combustor tubesheets ( aerovalve and resonance tube)
  - water makeup rate to the steam drum
  - compressed air flow to the flue gas spray quench atomizer
  - water flow to the flue gas spray quench atomizer
- Flue gas composition
  - decoupler exit
  - air plenum
- Cyclone solids collection
  - rate
  - particle size distribution
- Bed solids sample

  - initial
  - final
- Sound pressure level (dB)
  - at ~3 ft distance from air plenum
  - at ~3 ft distance from decoupler
  - in the vicinity of the fluidized bed
- Strain – gage rosettes at different locations on the fluidized bed vessel
- Heat flux meter on the tubesheet at pulse combustion chamber/resonance tube interface to estimate wall heat flux (?)

# APPENDIX B

# Operating Checkout Procedures

# *Clean Coal*

## *Pulse Combustor*
## *Design Qualification Test*

## **<u>Check List and Procedure for Startup</u>**

**<u>ThermoChem, Inc.</u>**

October 18, 2000

## 1. OVERVIEW

The following procedure is to be used for a cold startup of the steam reformer system. It is assumed that the vessel has all associated equipment installed, i.e. pulsed heater, cyclone, instrumentation, etc. It is also assumed that vessel entry procedures have been adhered to and that the manways are open for personnel access to the internals of the vessel and the pulsed heater air plenum.

The goals of a successful steam reformer startup are:

- Safety. The procedures provide for a safe startup of the reformer system for both personnel and equipment.
- Achievement of dry refractory to prolong equipment life. The pulsed heater combustion chamber must be dry and cured properly to minimize maintenance and prolong the life of the refractory.

## 2. CHECK LIST

### 2.1. Inspect and secure the reformer vessel

*2.1.1. **Warning: Vessel entry procedures must be adhered to prior to personnel entering the reformer.***

2.1.2. Remove unnecessary equipment, debris and foreign objects, if any, from reformer interior.

2.1.3. Carefully inspect the interior reformer walls for the integrity of the insulation boards. Make sure that the walls are fully covered by insulation and there are no bare spots. Also ascertain that the insulation is properly secured to the wall and is not free or loose. Correct deficiencies, if any.

2.1.4. Assure that all instrument taps, distributor bubble caps, water injector and bed drains are open and clear. Supplying air and verifying adequate flow from inside the vessel can check the bubble caps and instrument taps. The injector may be checked by temporarily connecting to an air hose and verifying flow. The drains should be visually inspected from inside the vessel using a flashlight. Correct deficiencies, if any.

2.1.5. Check all the vessel thermocouples for connectivity and integrity. Replace defective thermocouples, if any.

2.1.6. Inspect the resonance tube bundle to make sure that the inter-tube space is clear and there are no obstructions to fluidization. Clear debris, if any.

2.1.7. Check all the thermowells mounted on the pulse heater resonance tubes for mechanical integrity and the thermocouples for connectivity and integrity. Correct defects, if any. Verify that the thermowell junctions are located as specified in the drawing. Measure and record the data on the locations of all the thermowell junctions in the logbook.

2.1.8. Inspect the rope seal between the pulse heater decoupler and the decoupler housing for tightness of packing. Repack, if necessary.

2.1.9. Close and secure manways.

2.1.10. Close all bed drain and bed loading valves.

2.1.11. Carefully inspect the reformer exterior to make sure that all the ports are connected and there are no openings from the vessel to the outside. Cap the openings, if any.

**2.2. Inspect and secure the pulsed heater**

*2.2.1.* ***Warning: air plenum entry procedures must be adhered to prior to personnel entering the reformer.***

2.2.2. Remove unnecessary equipment, debris and foreign objects, if any, from the interior of the air plenum.

2.2.3. Inspect the aerovalve plate for proper orientation and alignment with reference to the resonance tubesheet. If incorrect, reorient and realign.

2.2.4. Assure that all instrument taps, aerovalves, resonance tubes, gas injection ports, flame sensor port and pilot burner ports are open and clear. Supplying air and verifying adequate flow from inside the air plenum can check the pilot burner ports and instrument taps. The gas injector can be checked by temporarily connecting to an air hose and verifying flow. The aerovalves should be visually inspected from inside the air plenum using a flashlight. Correct deficiencies, if any.

2.2.5. Check all the pulsed heater thermocouples for connectivity and integrity. Replace defective thermocouples, if any.

2.2.6. Perform a hydrostatic pressure test (535 psig) on the aerovalve plate water jacket. Record the data and the result in the logbook. If the test fails, inform the Project Manager of the result and wait for instructions regarding the next step.

2.2.7. Perform a hydrostatic pressure test (535 psig) on the pulse combustion chamber-resonance tube interface tubesheet water jacket. Record the data and the result in the logbook. If the test fails, inform the Project Manager of the result and wait for instructions regarding the next step.

2.2.8. Inspect the flame sensor for mechanical and signal integrity and the optical window for cleanliness.

2.2.9. Ascertain that a differential pressure transmitter is set up across the air plenum and pulse combustion chamber pressure taps. Correct, if necessary.

2.2.10. Ascertain that a differential pressure transmitter is set up across the pulse combustion chamber and the decoupler pressure taps. Correct, if necessary.

2.2.11. Use a borescope to inspect the integrity of refractory inside the pulse combustion chamber. Record the observations in the logbook. If there are large cracks or bare areas inform the Project Manager of the result and wait for instructions regarding the next step.

2.2.12. Inspect the flexible pipe connectors between the gas supply manifold and the aerovalve plate gas tubesheet for mechanical and flow integrity. The flex connectors can be checked by temporarily connecting to an air hose and verifying leak-free operation. Correct deficiencies, if any.

2.2.13. Inspect the water and steam pipe connections to the aerovalve plate water jacket for mechanical and flow integrity. Circulating water and verifying leak-free operation can check the connections. Correct deficiencies, if any.

2.2.14. Close and secure manway.

2.2.15. Inspect the seating of the flange/weight combination on the pressure relief support flange for proper seal. Correct, if necessary. Assure that the guard bolts are properly secured so that the weight can not fall off and cause injury. Secure the bolts, if necessary.

**2.3. Inspect and secure the balance of plant**

2.3.1. Inspect the Forced Draft fan mounting, electrical and piping connections for safe and leak free operation. Correct, if necessary.

2.3.2. Inspect the air compressor electrical and piping connections for safe and leak free operation. Correct, if necessary. If the compressor is diesel engine driven, check all the fluid (engine oil, diesel, etc.) levels. Add fluids as necessary.

2.3.3. Check the water and compressed air connections to the atomizer in the spray quench column. Correct, if necessary. Activate the spray and make sure that the atomizer delivers a fine mist with the droplets impinging on the column wall not before a travel of at least 10-ft axial distance from the sprayhead.

2.3.4. Assure that the cyclone exhaust vent and the pulsed heater exhaust vent are open and are free/clear from obstructions.

2.3.5. Assure that the cyclone catch drum is in place and is properly attached to the cyclone dipleg.

2.3.6. Assure that the gas trains (both pilot and pulse burners) and the burner management systems are set up for safe and leak free operation.

2.3.7. Assure that the premix air for fuel/air mixture supply to the pulse heater is set up for proper and safe operation.

2.3.8. Inspect the steam drum, the pressure relief valve and the piping connections. Correct, if necessary.

2.3.9. Verify proper operation of water level control and satisfactory supply of makeup water.

2.3.10. Ensure that dynamic pressure transducers are installed on the pulse combustion chamber and decoupler pressure taps and are connected to the Hewlett Packard Spectrum Analyzer.

2.3.11. Assure that the instrumentation (pressure transmitters, transducers, thermocouples and flow meters) actually in place are in agreement with those listed in the test plan, have the proper measurement range and are sufficient to provide all the measurements planned. Add if there are missing instrumentation.

2.3.12. Assure that the flue gas sampling line at decoupler exit is properly connected to the Continuous Emissions Monitoring System.

2.3.13. Assure that the sand to be used as fluid bed material has the particle size distribution specified in the test plan.

# 3. STARTUP PROCEDURE

## 3.1. Initialize

3.1.1. Instrument purges on air. Verify rotometer flow settings.

3.1.2. Start the air compressor.

3.1.3. Open the valve on the water line and supply water to the steam drum.

3.1.4. Open the steam vent.

## 3.2. Load sand to the reformer

3.2.1. Open the bed loading double block valves at the reformer.

3.2.2. Open lockhopper drain valve at media bin discharge.

3.2.3. Start bed loading conveying air.

3.2.4. Start lockhopper timer sequence to initiate sand flow to the conveying eductor. Sand is now being transferred from the media bin to the reformer.

3.2.5. Since the reformer cyclone is designed with sealing trickle valve on its dip leg, fluidization of the bed can be initiated during the bed loading process.

3.2.6. Admit fluidization air flow into the distributor and adjust air flow rate to correspond to about 1.4 feet per second of superficial fluidization velocity.

3.2.7. Verify that the bed level measurement is functional. This is an indicator of a well-fluidized bed.

3.2.8. When the media bin is empty as indicated by the bin level transmitter, shut off lockhopper unloading timer control (Media bin sized to hold only one reformer inventory).

3.2.9. Close drain valve at media bin discharge.

3.2.10. Shut off bed loading conveying air.

3.2.11. Close bed loading double block valves at reformer.

## 3.3. Preheat pulsed heater refractory with natural gas pilot burners

3.3.1. Assure that the water level in the steam drum corresponds to the preset level.

3.3.2. Switch on the water circulation pump to circulate water through the pulsed heater tubesheets.
3.3.3. Turn on the pulsed heater pilot burners to begin preheat of the combustion chamber refractories to 1,000°F.
3.3.4. The automatic Burner Management System (BMS) will purge the pulsed heater and light off the pilot burner automatically.
*3.3.5.* Set pilot fuel/air mixture rotameters to pre-designated (slightly below stoichiometric or slightly rich mixture) settings to maintain a heat-up rate no more than 50°F per hour if curing the refractory for the first time.
***3.3.6.* Follow the refractory curing procedure outlined below:**
3.3.7. Ramp from ambient temperature up to a combustion chamber temperature of 300 F at a rate not exceeding 50 F per hour.
3.3.8. Hold steady at this temperature for six (6) hours.
3.3.9. Ramp from 300 F to a combustion chamber temperature of 450 F at a rate not exceeding 50 F per hour.
3.3.10. Hold steady at this temperature for six (6) hours.
3.3.11. Ramp from 450 F to a combustion chamber temperature of 600 F at a rate not exceeding 25 F per hour.
3.3.12. Hold steady at this temperature for six (6) hours.
3.3.13. Ramp from 600 F to a combustion chamber temperature of 1,000 F at a rate not exceeding 50 F per hour.
3.3.14. Hold steady at this temperature for six (6) hours.
*3.3.15.* ***Caution: Heat up rate is not to exceed 25/50°F per hour to protect refractory during curing.***

**3.4. Fire pulsed heater on natural gas.**

3.4.1. After allowing sufficient elapsed time for purging air from the steam drum, close the steam vent to pressurize the pulsed heater water jackets.
3.4.2. Open the valves for water and air flow to the atomizer and start the water spray in the spray quench column.
3.4.3. With the pulsed heater combustion chamber preheated to 1,000°F by the pilot burners in step 3.3 and the tubes covered with bed material, perform the following:
3.4.4. Select natural gas firing in the control logic.
*3.4.5.* Set fuel/air mixture rotameters such that the nominal mixture ratio is 1:1 on a volumetric basis. This requires that the volumetric flow rates of fuel and air are equal to each other. Operational safety mandates that the mixture ratio is far removed from the flammability limit. ***Therefore, the air flow rate should never exceed 2 times the natural gas flow rate, on a volumetric basis.***
3.4.6. On the pulsed heater control, set tube temperature incrementally (10 to 50°F) and **iteratively** above the fluid bed temperature and set firing control in "auto". For example, if the bed temperature is 400°F, set heater tube temperature setpoint in the 410 to 450°F range such that the pulsed

heater combustion chamber temperature increase rate does not exceed 100 F per hour.

3.4.7. ***Caution: Heat up rate is not to exceed 100°F per hour in the pulsed heater combustion chamber to protect refractory.***

3.4.8. ***Caution: Do not exceed heater tube temperature setpoint of 1,200°F.***

3.4.9. The pulsed heaters will ignite on natural gas.

3.4.10. Verify that the heater is ignited by observing that the combustion chamber temperature is rising. Also monitor the dynamic pressure in the chamber.

3.4.11. If heater ignition fails, the BMS will automatically purge the heater and reinitiate the light off sequence.

### 3.5. Continue bed heat-up

3.5.1. ***Caution: Heat up rate is not to exceed 100°F per hour to protect vessel refractory.***

3.5.2. Continue heat-up of the bed to target operating temperature (1,120°F or as desired) by increasing the tube temperature setpoints in increments of 10 to 50°F. This will insure a steady and acceptable rate of temperature rise of the system's refractory.

3.5.3. Continue to verify bed temperature uniformity throughout the heat-up process.

### 3.6. Initiate water feed

3.6.1. When the reformer bed temperature reaches operating temperature, perform the following:

3.6.2. Open solenoid block valve on the water injectors.

3.6.3. Set bed temperature control to 1,120°F (or other setpoint as desired). The control will modulate the total water flow to maintain the fluid bed temperature setpoint.

3.6.4. Verify water flow has been established to each injector.

3.6.5. Verify that the pulsed heater firing controls are responding properly to the water reaction heat load and are maintaining a constant tube temperature setpoint.

3.6.6. Vary the pulsed heater tube temperatures as necessary to map out water throughput. For example, a lower water-processing rate will require less heat load to process. Therefore, a lower tube temperature setpoint will be required.

## 4. NORMAL SHUTDOWN PROCEDURE

The following procedure is to be used for normal shutdown of the reformer system.

### 4.1. Shut off water feed to the reformer

4.1.1. Close the water injector solenoid supply valves.

**4.2. Reduce pulsed heater firing rates**

4.2.1. Switch pulsed heaters to manual firing control.

4.2.2. Reduce firing rate initially by 1.5 MMBtu/h times the water flow rate to the reformer in gpm and in one (1) MMBtu per hour increment afterwards.

4.2.3. Continue to reduce firing rates to achieve bed temperature rate of drop no more than 100°F per hour or pulsed heater combustion chamber temperature rate of drop of no more than 100°F per hour to protect refractory.

4.2.4. ***Caution: Cool down rate is not to exceed 100°F per hour to protect refractory.***

**4.3. Turn off pulsed heater**

4.3.1. Set pulsed heater firing controller to "zero".

4.3.2. The BMS will initiate a burner air purge for shutdown.

4.3.3. Shut off combustion air supply fan.

4.3.4. Turn off water and air flows to the atomizer in the spray quench column.

4.3.5. Turn off water circulation pump.

**4.4. Shut off fluidization air flow and the purges**

4.4.1. Turn fluidization air flow off.

4.4.2. Turn instrument air purges off.

# APPENDIX C

# Test Input Data

**TEST DATE** 3/13/01 13:30 HR

**INPUTS**

---------------------------------------------- **DATA TO BE ENTERED IN** CELLS

**NO. OF PULSE HEATERS** 1

| | | |
|---|---|---|
| AMBIENT AIR PRESSURE | [illegible] | PSI |
| AMBIENT AIR TEMPERATURE | [illegible] | F |
| RELATIVE HUMIDITY | [illegible] | |

**FUEL TYPE:** ENTER IN CELL BELOW: 1 FOR NATGAS
[illegible] 2 FOR PROPANE
3 FOR REFORMATE GAS

| | NAT GAS WT% | | NAT GAS 1 | PROPANE 2 | REFORMATE GAS 3 |
|---|---|---|---|---|---|
| ASH | 0.00% | | 0.00% | 0.00% | 0.00% |
| MOISTURE | 0.00% | | 0.00% | 0.00% | 12.48% |
| CARBON | 74.06% | | 74.06% | 81.68% | 24.75% |
| HYDROGEN | 24.01% | | 24.01% | 18.32% | 8.39% |
| SULFUR | 0.00% | | 0.00% | 0.00% | 0.11% |
| NITROGEN | 0.81% | | 0.81% | 0.00% | 0.00% |
| OXYGEN | 1.12% | | 1.12% | 0.00% | 54.28% |
| CHLORINE | 0.00% | | 0.00% | 0.00% | 0.00% |
| **TOTAL** | 100.00% | | 100.000% | 100.000% | 100.000% |
| HHV,BTU/LB | 23,133 | BTU/LB | 23,133 | 21,500 | 5,913 |
| SPECIFIC HEAT OF FUEL,BTU/LB-F | 0.532 | | 0.532 | 0.407 | 0.50 |
| MOLECULAR WEIGHT,LB/LB MOLE | 17.191 | | 17.19 | 44.11 | 14.92 |
| STANDARD DENSITY,LB/FT3 | 0.045 | | 0.045 | 0.116 | 0.039 |
| HHV,BTU/SCF | 1,050 | | 1,050 | 2,504 | 233 |

IF FUEL TYPE IS 3 ABOVE,
ENTER VALUES BELOW:

FUEL GAS COMPOSITION **REFORMATE GAS**

| | V% | | LB/MOL GAS | LB/LB | HHV | LHV | SPCF HEAT |
|---|---|---|---|---|---|---|---|
| H2 | [illegible] | 0.59 | 1.19 | 8.00% | 4,890 | 4,132 | 0.274559 |
| CO | [illegible] | 0.11 | 2.17 | 14.51% | 631 | 631 | 0.036137 |
| CO2 | 21.44% | 0.21 | 9.44 | 63.25% | - | - | 0.128389 |
| CH4 | [illegible] | 0.02 | 0.18 | 1.20% | 288 | 259 | 0.00641 |
| C2H6 | [illegible] | 0.00 | 0.02 | 0.12% | 27 | 25 | 0.000517 |
| C2H4 | 0.11% | 0.00 | 0.03 | 0.21% | 45 | 42 | 0.00085 |
| C3H6 | 0.04% | 0.00 | 0.02 | 0.11% | 24 | 22 | 0.000451 |
| C3H8 | [illegible] | 0.00 | 0.00 | 0.00% | - | - | 0 |
| H2S | [illegible] | 0.00 | 0.02 | 0.11% | 8 | 7 | 0.000286 |
| CH3SH | [illegible] | 0.00 | 0.00 | 0.00% | - | - | 0 |
| (CH3)2S | [illegible] | 0.00 | 0.00 | 0.00% | - | - | 0 |
| (CH3)2S2 | [illegible] | 0.00 | 0.00 | 0.00% | - | - | 0 |
| HCl | [illegible] | 0.00 | 0.00 | 0.00% | - | - | 0 |
| H2O (v) | [illegible] | 0.10 | 1.86 | 12.48% | - | - | 0.055523 |
| | 100.0000% | 1.04 | MW 14.92 LB/LB-MOLE | 100.00% | 5,913 BTU/LB | 5,118 BTU/LB | 0.50 |

| | |
|---|---|
| HHV, Btu/SCF | 233 |
| LHV, Btu/SCF | 201 |
| LHV, Btu/Lb | 5,118 |

INPUT

| | | | |
|---|---|---|---|
| PERCENT EXCESS AIR | [illegible] | | |
| FUEL(+AIR?) INJECTION: AIR PREMIXING,MASS BASIS | 0% | [illegible] | |
| AIR PREHEAT | NO | | |
| FUEL GAS SUPPLY TEMPERATURE, F | [illegible] | | |
| COMBUSTION AIR TEMPERATURE, F | [illegible] | 46 | |
| BED TEMPERATURE, F | [illegible] | | |
| COMBUSTION AIR SUPPLY PRESSURE,INCH WC | [illegible] | 0.33 PSIG | |
| DESIGN FIRING RATE PER HEATER,MMBTU/H | 21.57 | [illegible] MAIN | 0.57 PILOTS |
| RECYCLE FLUE GAS TEMPERATURE, F | 461 | | |
| FLUE GAS INLET TEMP TO FAN, F | 147 | 147 | |

| TEST NO. | DATE | TIME | FIR RATE MMBTU/H | DILUTION AIR | RECYCLE | FRESH AIR T | RECYCLE T | FAN INLET T | AIR PLENUM P |
|---|---|---|---|---|---|---|---|---|---|
| 3-7 | 3/13/01 | 13:30 | 21.20 | NO | 1 | 43 | 461 | 147 | 9.19 |

| AIR PLENUM T | CHAMBER T | DECOUPLER T | MUFFLER T | BED T | BED HEIGHT INCH | FL VELOCITY |
|---|---|---|---|---|---|---|
| 463 | 2,448 | 1279 | 700 | 959 | 94.2 | 1.23 |

FLUE GAS ANALYSIS

| O2 % | CO2 % | CO PPMV | NOX PPMV | THC PPMV |
|---|---|---|---|---|
| 4.55 | 9.06 | 177 | 19 | 2 |

# APPENDIX D

# Property Data

## THERMODYNAMIC & TRANSPORT DATA

### Heat Capacity

Units = cal/(gmole)(K)
Form: Cp = a + b*t + c*t^2 + d*t^3

| | a | b | c | d |
|---|---|---|---|---|
| N2 | 7.07 | -0.00132 | 3.31E-06 | -1.26E-09 |
| CO2 | 5.14 | 0.0154 | -9.94E-06 | 2.42E-09 |
| H2O (v) | 8.1 | -0.00072 | 3.63E-06 | -1.16E-09 |
| SO2 | 5.85 | 0.0154 | -1.11E-05 | 2.91E-09 |
| O2 | 6.22 | 0.00271 | -3.7E-07 | -2.2E-10 |

### Thermal Conductivity

Units = microcal/s/cm/K
Form: Kg = a + b*t + c*t^2 + d*t^3

| | a | b | c | d |
|---|---|---|---|---|
| N2 | 0.9359 | 0.2344 | -0.000121 | 3.591E-08 |
| CO2 | -17.23 | 0.1914 | 1.308E-05 | -2.514E-08 |
| H2O (v) | 17.53 | -0.0242 | 0.00043 | -2.173E-07 |
| SO2 | -19.31 | 0.1515 | -0.000033 | 5.5E-09 |
| O2 | -0.7816 | 0.238 | -8.94E-05 | 2.324E-08 |

### Gas Viscosity

Units = micropoise
Form: Mu = a + b*t + c*t^2

| | a | b | c |
|---|---|---|---|
| N2 | 30.43 | 0.4989 | -0.000109 |
| CO2 | 25.45 | 0.4549 | -8.65E-05 |
| H2O (v) | -31.89 | 0.4145 | -8.27E-06 |
| SO2 | -3.793 | 0.4645 | -7.28E-05 |
| O2 | 18.11 | 0.6632 | -0.000188 |

### Molecular Weights & Heating Values

| | Lb/LbMole | HHV Btu/Lb | LHV Btu/Lb |
|---|---|---|---|
| O2 | 32 | | |
| N2 | 28.01 | | |
| H2 | 2.02 | 61095 | 51623 |
| CO | 28.01 | 4347 | 4347 |
| CO2 | 44.01 | | |
| CH4 | 16.05 | 23875 | 21495 |
| C2H6 | 30.08 | 22323 | 20418 |
| C2H4 | 28.06 | 21636 | 20275 |
| C3H6 | 42.09 | 21048 | 19687 |
| C3H8 | 44.11 | 21669 | 19937 |
| H2S | 34.08 | 7097 | 6537 |
| CH3SH | 48.11 | 13599 | 12820 |
| (CH3)2S | 62.14 | 15103 | 14198 |
| (CH3)2S2 | 94.20 | 11317 | 10721 |
| HCl | 36.46 | | |
| H2O (v) | 18.02 | | |
| SO2 | 64.06 | | |
| C4H10 | 58.14 | 21296 | 19653 |

| Fuel Gas Heat Capacities | | a | b | c | d |
|---|---|---|---|---|---|
| | H2 | 6.88 | -0.000022 | 2.1E-07 | 1.3E-10 |
| | CO | 6.92 | -0.00065 | 0.0000028 | -1.14E-09 |
| | CO2 | 5.14 | 0.0154 | -9.94E-06 | 2.42E-09 |
| | CH4 | 5.04 | 0.00932 | 8.87E-06 | -5.37E-09 |
| | C2H6 | 2.46 | 0.0361 | -0.000007 | -4.6E-10 |
| | C2H4 | 0.934 | 0.0369 | -1.93E-05 | 4.01E-09 |
| | C3H8 | | | | |
| | H2S | 7.2 | 0.0036 | | |
| | H2O | 8.10 | -7.20E-04 | 3.63E-06 | -1.16E-09 |

ORIFICE FLOW COEFFICIENT

C0 = 0.59181
\+ 0.02244 *BETA

| BETA | C0 | CURVE-FIT |
|---|---|---|
| 0.2 | 0.5969 | 0.5963 |
| 0.25 | 0.5975 | 0.5974 |
| 0.3 | 0.5983 | 0.5985 |
| 0.35 | 0.5992 | 0.5997 |
| 0.4 | 0.6003 | 0.6008 |
| 0.45 | 0.6016 | 0.6019 |
| 0.5 | 0.6031 | 0.6030 |
| 0.55 | 0.6045 | 0.6042 |
| 0.6 | 0.6059 | 0.6053 |
| 0.65 | 0.6068 | 0.6064 |
| 0.7 | 0.6069 | 0.6075 |

ASME HANDBOOK, CURVE-FIT
PAGE 3-65

C1 = 91.70803517
* BETA^ 1.74996

| BETA | C1 | CURVE-FIT |
|---|---|---|
| 0.2 | 5.486 | 5.486 |
| 0.25 | 8.106 | 8.106 |
| 0.3 | 11.153 | 11.153 |
| 0.35 | 14.606 | 14.606 |
| 0.4 | 18.451 | 18.451 |
| 0.45 | 22.675 | 22.675 |
| 0.5 | 27.266 | 27.266 |
| 0.55 | 32.215 | 32.215 |
| 0.6 | 37.513 | 37.513 |
| 0.65 | 43.153 | 43.153 |
| 0.7 | 49.129 | 49.129 |

ASME HANDBOOK, CURVE-FIT
PAGE 3-65

| LN(BETA) | LN(C1) | LN(C1) = 4.51861 + 1.74996 *LN(BETA) |
|---|---|---|
| -1.609 | 1.702 | 1.702 |
| -1.386 | 2.093 | 2.093 |
| -1.204 | 2.412 | 2.412 |
| -1.050 | 2.681 | 2.681 |
| -0.916 | 2.915 | 2.915 |
| -0.799 | 3.121 | 3.121 |
| -0.693 | 3.306 | 3.306 |
| -0.598 | 3.472 | 3.472 |
| -0.511 | 3.625 | 3.625 |
| -0.431 | 3.765 | 3.765 |
| -0.357 | 3.894 | 3.894 |
| | | CURVE-FIT |

**TUBE SIZES**

| ID,INCH | OD,INCH | WALL THK | BWG GAUGE |
|---|---|---|---|
| 0.206 | 0.25 | 0.022 | 24 |
| 0.305 | 0.375 | 0.035 | 20 |
| 0.402 | 0.5 | 0.049 | 18 |
| 0.495 | 0.625 | 0.065 | 16 |
| 0.606 | 0.75 | 0.072 | 15 |
| 0.709 | 0.875 | 0.083 | 14 |
| 0.81 | 1 | 0.095 | 13 |
| 1.032 | 1.25 | 0.109 | 12 |
| 1.282 | 1.5 | 0.109 | 12 |
| 1.76 | 2 | 0.12 | 11 |
| 2.204 | 2.5 | 0.148 | 9 |

**PIPE SIZES**

| NOMNL,IN | ID,INCH | OD,INCH | WALL THK | SCHEDULE |
|---|---|---|---|---|
| 0.125 | 0.269 | 0.405 | 0.068 | 40 |
| 0.25 | 0.364 | 0.54 | 0.088 | 40 |
| 0.375 | 0.493 | 0.675 | 0.091 | 40 |
| 0.5 | 0.622 | 0.84 | 0.109 | 40 |
| 0.75 | 0.824 | 1.05 | 0.113 | 40 |
| 1 | 1.049 | 1.315 | 0.133 | 40 |
| 1.25 | 1.38 | 1.66 | 0.14 | 40 |
| 1.5 | 1.61 | 1.9 | 0.145 | 40 |
| 2 | 2.067 | 2.375 | 0.154 | 40 |
| 2.5 | 2.469 | 2.875 | 0.203 | 40 |
| 3 | 3.068 | 3.5 | 0.216 | 40 |
| 3.5 | 3.548 | 4 | 0.226 | 40 |
| 4 | 4.026 | 4.5 | 0.237 | 40 |
| 5 | 5.047 | 5.563 | 0.258 | 40 |
| 6 | 6.065 | 6.625 | 0.28 | 40 |
| 8 | 7.981 | 8.625 | 0.322 | 40 |
| 10 | 10.02 | 10.75 | 0.365 | 40 |
| 12 | 12 | 12.75 | 0.375 | 40 |
| 14 | 13.25 | 14 | 0.375 | STD |
| 16 | 15.25 | 16 | 0.375 | STD |
| 18 | 17.25 | 18 | 0.375 | STD |
| 20 | 19.25 | 20 | 0.375 | STD |
| 22 | 21.25 | 22 | 0.375 | STD |
| 24 | 23.25 | 24 | 0.375 | STD |
| 26 | 25.25 | 26 | 0.375 | STD |
| 28 | 27.25 | 28 | 0.375 | STD |
| 30 | 29.25 | 30 | 0.375 | STD |
| 32 | 31.25 | 32 | 0.375 | STD |
| 34 | 33.25 | 34 | 0.375 | STD |
| 36 | 35.25 | 36 | 0.375 | STD |
| 42 | 41.25 | 42 | 0.375 | STD |
| 48 | 47.25 | 48 | 0.375 | STD |

## VISCOSITY OF STEAM

| TEMPERATURE K | VISCOSITY NS/M2 *10^7 | TEMPERATURE F | VISCOSITY LB/FT-H | MU = 0.01988 + 4.849E-05 *TEMP | CORRELATION A24:D33 |
|---|---|---|---|---|---|
| 380 | 127.1 | 224 | 0.0307 | 0.0308 | 0.0301 |
| 400 | 134.4 | 260 | 0.0325 | 0.0325 | 0.0321 |
| 450 | 152.5 | 350 | 0.0369 | 0.0369 | 0.0370 |
| 500 | 170.4 | 440 | 0.0412 | 0.0412 | 0.0419 |
| 550 | 188.4 | 530 | 0.0456 | 0.0456 | 0.0468 |
| 600 | 206.7 | 620 | 0.0500 | 0.0500 | 0.0517 |
| 650 | 224.7 | 710 | 0.0544 | 0.0543 | 0.0566 |
| 700 | 242.6 | 800 | 0.0587 | 0.0587 | 0.0615 |
| 750 | 260.4 | 890 | 0.0630 | 0.0630 | 0.0664 |
| 800 | 278.6 | 980 | 0.0674 | 0.0674 | 0.0712 |
| 850 | 296.9 | 1070 | 0.0718 | 0.0718 | 0.0761 |
| | | | | CURVE-FIT | |

## VISCOSITY OF AIR

| TEMPERATURE K | VISCOSITY NS/M2 *10^7 | TEMPERTR F | VISCOSITY LB/FT-H | MU = 0.04725 + 4.029E-05 *TEMP |
|---|---|---|---|---|
| 300 | 184.6 | 80 | 0.0447 | 0.0505 |
| 350 | 208.2 | 170 | 0.0504 | 0.0541 |
| 400 | 230.1 | 260 | 0.0557 | 0.0577 |
| 450 | 250.7 | 350 | 0.0606 | 0.0614 |
| 500 | 270.1 | 440 | 0.0653 | 0.0650 |
| 550 | 288.4 | 530 | 0.0698 | 0.0686 |
| 600 | 305.8 | 620 | 0.0740 | 0.0722 |
| 650 | 322.5 | 710 | 0.0780 | 0.0759 |
| 700 | 338.8 | 800 | 0.0820 | 0.0795 |
| 750 | 354.6 | 890 | 0.0858 | 0.0831 |
| 800 | 369.8 | 980 | 0.0895 | 0.0867 |
| 850 | 384.3 | 1070 | 0.0930 | 0.0904 |
| 900 | 398.1 | 1160 | 0.0963 | 0.0940 |
| 950 | 411.3 | 1250 | 0.0995 | 0.0976 |
| 1000 | 424.4 | 1340 | 0.1027 | 0.1012 |
| 1100 | 449.0 | 1520 | 0.1086 | 0.1085 |
| 1200 | 473.0 | 1700 | 0.1144 | 0.1157 |
| 1300 | 496.0 | 1880 | 0.1200 | 0.1230 |
| 1400 | 530.0 | 2060 | 0.1282 | 0.1303 |
| 1500 | 557.0 | 2240 | 0.1347 | 0.1375 |
| | | | | CURVE-FIT |

## THERMAL CONDUCTIVITY OF STEAM

| TEMPERATURE K | THERMAL CONDUC W/M-K *10^3 | TEMPERATURE F | TH CONDUC BTU/H-FT-F | K = 0.007962 + 0.0000267 *TEMP |
|---|---|---|---|---|
| 380 | 24.6 | 224 | 0.0142 | 0.0140 |
| 400 | 26.1 | 260 | 0.0151 | 0.0149 |
| 450 | 29.9 | 350 | 0.0173 | 0.0173 |
| 500 | 33.9 | 440 | 0.0196 | 0.0197 |
| 550 | 37.9 | 530 | 0.0219 | 0.0221 |
| 600 | 42.2 | 620 | 0.0244 | 0.0245 |
| 650 | 46.4 | 710 | 0.0268 | 0.0269 |
| 700 | 50.5 | 800 | 0.0292 | 0.0293 |
| 750 | 54.9 | 890 | 0.0317 | 0.0317 |
| 800 | 59.2 | 980 | 0.0342 | 0.0341 |
| 850 | 63.7 | 1070 | 0.0368 | 0.0365 |
| | | | | CURVE-FIT |

## THERMAL CONDUCTIVITY OF AIR

| TEMPERATURE K | THERMAL CONDUC W/M-K *10^3 | TEMPERATURE F | TH CONDUC BTU/H-FT-F | K = 0.015012 + 0.0000181 *TEMP |
|---|---|---|---|---|
| 300 | 26.3 | 80 | 0.0152 | 0.0165 |
| 350 | 30.0 | 170 | 0.0173 | 0.0181 |
| 400 | 33.8 | 260 | 0.0195 | 0.0197 |
| 450 | 37.3 | 350 | 0.0216 | 0.0214 |
| 500 | 40.7 | 440 | 0.0235 | 0.0230 |
| 550 | 43.9 | 530 | 0.0254 | 0.0246 |
| 600 | 46.9 | 620 | 0.0271 | 0.0262 |
| 650 | 49.7 | 710 | 0.0287 | 0.0279 |
| 700 | 52.4 | 800 | 0.0303 | 0.0295 |
| 750 | 54.9 | 890 | 0.0317 | 0.0311 |
| 800 | 57.3 | 980 | 0.0331 | 0.0328 |
| 850 | 59.6 | 1070 | 0.0344 | 0.0344 |
| 900 | 62.0 | 1160 | 0.0358 | 0.0360 |
| 950 | 64.3 | 1250 | 0.0372 | 0.0376 |
| 1000 | 66.7 | 1340 | 0.0385 | 0.0393 |
| 1100 | 71.5 | 1520 | 0.0413 | 0.0425 |
| 1200 | 76.3 | 1700 | 0.0441 | 0.0458 |
| 1300 | 82.0 | 1880 | 0.0474 | 0.0490 |
| 1400 | 91.0 | 2060 | 0.0526 | 0.0523 |
| 1500 | 100.0 | 2240 | 0.0578 | 0.0556 |
| | | | | CURVE-FIT |

# APPENDIX E

# Pulse Combustor Test Data Analysis

PULSE COMBUSTOR TEST DATA ANALYSIS -- 253 TUBE MODULE 8/24/01 21-Mar-02

**STOICHIOMETRY**

| | | | |
|---|---|---|---|
| FUEL TYPE: | NAT GAS | | |
| ASH | 0.00% | LB AIR/LB COMPONENT | |
| MOISTURE | 0.00% | | |
| CARBON | 74.06% | 11.43 | 8.466 |
| HYDROGEN | 24.01% | 33.98 | 8.158 |
| SULFUR | 0.00% | 4.28 | 0.000 |
| NITROGEN | 0.81% | | |
| OXYGEN | 1.12% | -4.29 | -0.048 |
| CHLORINE | 0.00% | | ================ |
| STOICHIOMETERIC AIR (LBS DRY AIR/LB FUEL) | | | 16.575 |
| HUMIDITY RATIO | 0.0132 | LB WATER/LB DRY AIR | |
| STOICHIOMETRIC AIR(LBS WET AIR/LB FUEL) | | | 16.793 |
| WATER IN AIR(LB WATER/LB FUEL) | | | 0.218 |

| | | |
|---|---|---|
| HHV OF FUEL: | 23,133 | BTU/LB FUEL |
| MOISTURE IN FLUE: | 2.14 | LB/LB FUEL |
| LATENT HEAT: | 2,245 | BTU/LB FUEL |
| LHV OF FUEL: | 20,888 | BTU/LB FUEL |

**QUICK OVERALL BALANCE**

| | | | | | |
|---|---|---|---|---|---|
| INLET AIR PRESSURE | 15.03 | PSIA | 1.02 | | |
| INLET AIR TEMPERATURE | 43 | F | | | |
| INLET AIR COMPOSITION | | | | MASS PERCENT | |
| -OXYGEN | 3.864 | LB O2/LB FUEL | | 0.23 | |
| -NITROGEN | 12.712 | LB N2/LB FUEL | | 0.76 | |
| -WATER | 0.218 | LB WATER/LB FUEL | | 0.01 | |
| INLET AIR THETA FN FOR CP | 2.79 | | | 2.79 | 3.00 |
| SPECIFIC HEATS | | | | | |
| -OXYGEN | 0.221 | BTU/LB O2-R | | 1.744 | 1.790 |
| -NITROGEN | 0.249 | BTU/LB N2-R | | 3.339 | 3.390 |
| -WATER | 0.448 | BTU/LB WTR-R | | 1.492 | 1.585 |
| COMBUSTION STOICHIOMETRY | ***121.92%*** | | | | |
| TOTAL INLET FLOW | | 26.246 LB TOTAL/LB FUEL | | | |
| INLET ENTHALPY | | | | | |
| -OXYGEN | -38.47 | BTU/LB FUEL | | | |
| -NITROGEN | -142.53 | BTU/LB FUEL | | | |
| -WATER | -4.40 | BTU/LB FUEL | | | |
| FRACTN HEAT REL FROM FUEL | 100.00% | | 0 | | |
| EFFEC HEAT REL FROM FUEL | 100.00% | | | | |
| TOTAL HEAT LOSS | 51.21% | | ***48.8%*** | | |
| TOTAL INLET ENTHALPY | | 23,562 | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| COMBUSTION PRODUCTS | | | | | | | | | | |
| EXIT TEMPERATURE 1 | 1,279 | F | | **1,279** | | | | | | |
| THETA FUNCTN FOR CP | 9.66 | | | | | 9.66 | 3.00 | | | |
| SPECIFIC HEATS | | | | | | | | | | |
| -OXYGEN | 0.241 | BTU/LB O2-R | | | | 3.393 | 1.790 | | | |
| -NITROGEN | 0.261 | BTU/LB N2-R | | | | 5.125 | 3.390 | | | |
| -WATER | 0.489 | BTU/LB WTR-R | | | | 4.841 | 1.584 | | | |
| -CO2 | 0.256 | BTU/LB CO2-R | | | | 2.122 | 0.414 | | | |
| -CO | 0.263 | BTU/LB CO-R | | | | 5.504 | 3.752 | | | |
| -HYDROGEN | 3.479 | BTU/LB H2-R | | | | -166.448 | -189.614 | | | |
| -CH4 | 0.798 | BTU/LB CH4-R | | | | 11.198 | 5.883 | | | |
| -HCl | 0.196 | BTU/LB HCl-R | | | | 1.919 | 0.614 | | | |
| -NO | 0.252 | BTU/LB NO-R | | | | 0.409 | -1.268 | | | |
| -SO2 | 0.167 | BTU/LB SO2-R | | | | 1.508 | 0.397 | | | |
| -SO3 | 0.159 | BTU/LB SO3-R | | | | | | | | |
| -ASH | 0.250 | BTU/LB ASH-R | | | | | | | | |
| EXIT FLOWS | LB COMP/LB FUEL | | | | | | VOL PCT WET | | VOL PCT DRY | |
| -OXYGEN | 0.970 | | | 0.030 | MOL | | 3.07 | % | 4.18 | % |
| -NITROGEN | 17.502 | | | 0.625 | | | 63.33 | % | 86.24 | % |
| -WATER | 4.722 | | 2.142 | 0.262 | | 0.27 | 26.56 | % | | |
| -CO2 | 3.049 | | | 0.069 | | 0.07 | 7.02 | % | 9.56 | % |
| -CO | 0.004 | | ***0.00*** | 0.000 | | | 132.89 | PPMV | 180.95 | PPMV |
| -HYDROGEN | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -CH4 | 0.000 | | ***0.00*** | 0.000 | | | 1.50 | PPMV | 2.04 | PPMV |
| -HCl | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -NO | 0.000 | | ***0.024*** | 0.000 | | | 14.26 | PPMV | 19.42 | PPMV |
| -SO2 | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -SO3 | 0.000 | | 0.00 | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -ASH | 0.000 | | | | | | 100.00 | | 100.00 | |
| TOTAL | | | 26.246 | 0.987 | | | 26.60 | | | |
| | | | 100.000% | | | | MOL WT | | | |
| EXIT ENTHALPIES | BTU/LB FUEL | | | | | | | | | |
| -OXYGEN | 279.8 | | | | | | | | | |
| -NITROGEN | 5466.7 | | | | | | | | | |
| -WATER | 2768.9 | | | | | | | | | |
| -CO2 | 937.4 | | | | | | | | | |
| -CO | 1.2 | | | | | | | | | |
| -HYDROGEN | 0.0 | | | | | | | | | |
| -CH4 | 0.0 | | | | | | | | | |
| -HCl | 0.0 | | | | | | | | | |
| -NO | 0.1 | | | | | | | | | |
| -SO2 | 0.0 | | | | | | | | | |
| -SO3 | 0.0 | | | | | | | | | |
| -ASH | 0.0 | | | | | | | | | |
| TOTAL | | | 23,562 | | | | | | | |
| FIRING RATE: | | | **2.18E+07** | BTU/HR | | 0.57 | | | | |
| AIR REQUIREMENT FOR COMBUSTION: | | | 25.25 | LB air/LB fuel | | | | | | |
| FUEL FLOW RATE: | | | 941 | LB/HR | | 346 | scfm | | | |
| TOTAL AIR FLOW: | | | 23,757 | LB/HR | | 5,351 | scfm | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| PC EXHAUST TEMPERATURE: | | | 1,279 F | | | | | | | |
| | **WATER QUENCH** | | | | | | | | | |
| INLET WATER PRESSURE | 60.00 | PSIA | | | | | | | | |
| INLET WATER TEMPERATURE | 38 | F | | | | | | | | |
| INLET WATER FLOW RATE,LB/H | ***12,508*** | LB/H | | 24.99 | GPM | | SPRAYING SYSTEMS CO. | | | |
| | 13.29 | LB/LB FUEL | | | | | FLOMAX AIR ATOMIZING NOZZLE | | | |
| INLET AIR FLOW RATE | 444.13 | LB/H | | 100.03 | SCFM | | | | | |
| | 0.47 | LB/LB FUEL | | | | | | | | |
| TOTAL INLET FLOW | | | 40.011 LB/LB FUEL | | | | | | | |
| INLET ENTHALPY | | | | | | | | | | |
| -FLUE GAS | 23089.54 | BTU/LB FUEL | | 5% | | | | | | |
| -WATER | -558.28 | BTU/LB FUEL | | | | | | | | |
| -AIR | -3.33 | BTU/LB FUEL | | | | | | | | |
| TOTAL INLET ENTHALPY | | | 22,528 | | | | | | | |
| COMBUSTION PRODUCTS | | | | | | | | | | |
| EXIT TEMPERATURE 1 | 700 | F | | 700.00 | | | | | | |
| THETA FUNCTN FOR CP | 6.44 | | | | | 6.44 | 3.00 | | | |
| SPECIFIC HEATS | | | | | | | | | | |
| -OXYGEN | 0.231 | BTU/LB O2-R | | | | 2.584 | 1.790 | | | |
| -NITROGEN | 0.252 | BTU/LB N2-R | | | | 4.259 | 3.390 | | | |
| -WATER | 0.464 | BTU/LB WTR-R | | | | 3.181 | 1.584 | | | |
| -CO2 | 0.236 | BTU/LB CO2-R | | | | 1.226 | 0.414 | | | |
| -CO | 0.131 | BTU/LB CO-R | | | | 4.627 | 3.752 | | | |
| -HYDROGEN | 3.450 | BTU/LB H2-R | | | | -177.737 | -189.614 | | | |
| -CH4 | 0.798 | BTU/LB CH4-R | | | | 11.198 | 5.883 | | | |
| -HCl | 0.196 | BTU/LB HCl-R | | | | 1.919 | 0.614 | | | |
| -NO | 0.252 | BTU/LB NO-R | | | | 0.409 | -1.268 | | | |
| -SO2 | 0.156 | BTU/LB SO2-R | | | | 0.935 | 0.397 | | | |
| -SO3 | 0.148 | BTU/LB SO3-R | | | | | | | | |
| -ASH | 0.250 | BTU/LB ASH-R | | | | | | | | |
| EXIT FLOWS | LB COMP/LB FUEL | | | | | | VOL PCT WET | | VOL PCT DRY | |
| -OXYGEN | 1.078 | | | 0.034 | MOL | | 1.94 | % | 4.55 | % |
| -NITROGEN | 17.859 | | | 0.638 | | | 36.63 | % | 86.08 | % |
| -WATER | 18.020 | | 13.292 | 1.000 | | 0.57 | 57.45 | % | | |
| -CO2 | 3.049 | | | 0.069 | | 0.04 | 3.98 | % | 9.35 | % |
| -CO | 0.004 | | | 0.000 | | | 75.32 | PPMV | 177.00 | PPMV |
| -HYDROGEN | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -CH4 | 0.000 | | | 0.000 | | | 0.85 | PPMV | 2.00 | PPMV |
| -HCl | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -NO | 0.000 | | | 0.000 | | | 8.09 | PPMV | 19.00 | PPMV |
| -SO2 | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -SO3 | 0.000 | | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -ASH | 0.000 | | | | | | 100.00 | | 100.00 | |
| TOTAL | | | 40.011 | 1.741 | | | 22.98 | | | |
| | | | 100.000% | | | | MOL WT | | | |

| | | | | | |
|---|---|---|---|---|---|
| EXIT ENTHALPIES | BTU/LB FUEL | | | | |
| -OXYGEN | 154.1 | | | | |
| -NITROGEN | 2793.1 | | | | |
| -WATER | 5183.9 | | | | |
| -CO2 | 445.6 | | | | |
| -CO | 0.3 | | | | |
| -HYDROGEN | 0.0 | | | | |
| -CH4 | 0.0 | | | | |
| -HC1 | 0.0 | | | | |
| -NO | 0.1 | | | | |
| -SO2 | 0.0 | | | | |
| -SO3 | 0.0 | | | | |
| -ASH | 0.0 | | | | |
| TOTAL | | 22,528 | | | |

**WATER QUENCH FOR FLUE GAS RECIRCULATION**

| | | | | | | |
|---|---|---|---|---|---|---|
| INLET WATER PRESSURE | 60.00 | PSIA | | | | SPRAYING SYSTEMS CO. |
| INLET WATER TEMPERATURE | 38 | F | 5.06 GPM | | | FINE SPRAY HYDRAULIC ATOMIZING SPRAY NOZZLE |
| INLET WATER FLOW RATE,LB/H | 2,531 | LB/H | | | | |
| | 2.69 | LB/LB FUEL | | | | |
| INLET AIR FLOW RATE | 0.00 | LB/H | 0.00 SCFM | | | |
| | 0.00 | LB/LB FUEL | | | | |
| TOTAL INLET FLOW | | 42.700 LB/LB FUEL | | | | |
| INLET ENTHALPY | | | | | | |
| -FLUE GAS | 22528.10 | BTU/LB FUEL | | | | |
| -WATER | -112.95 | BTU/LB FUEL | | | | |
| -AIR | 0.00 | BTU/LB FUEL | | | | |
| TOTAL INLET ENTHALPY | | 22,415 | | | | |
| COMBUSTION PRODUCTS | | | | | | |
| EXIT TEMPERATURE 1 | 461 | F | | | | |
| THETA FUNCTN FOR CP | 5.11 | | | 5.11 | 3.00 | |
| SPECIFIC HEATS | | | | | | |
| -OXYGEN | 0.226 | BTU/LB O2-R | | 2.267 | 1.790 | |
| -NITROGEN | 0.250 | BTU/LB N2-R | | 3.918 | 3.390 | |
| -WATER | 0.455 | BTU/LB WTR-R | | 2.547 | 1.584 | |
| -CO2 | 0.225 | BTU/LB CO2-R | | 0.889 | 0.414 | |
| -CO | 0.080 | BTU/LB CO-R | | 4.282 | 3.752 | |
| -HYDROGEN | 3.446 | BTU/LB H2-R | | -182.325 | -189.614 | |
| -CH4 | 0.798 | BTU/LB CH4-R | | 11.198 | 5.883 | |
| -HC1 | 0.196 | BTU/LB HC1-R | | 1.919 | 0.614 | |
| -NO | 0.252 | BTU/LB NO-R | | 0.409 | -1.268 | |
| -SO2 | 0.152 | BTU/LB SO2-R | | 0.717 | 0.397 | |
| -SO3 | 0.144 | BTU/LB SO3-R | | | | |
| -ASH | 0.250 | BTU/LB ASH-R | | | | |

| EXIT FLOWS | LB COMP/LB FUEL | | | | | VOL PCT WET | | VOL PCT DRY | |
|---|---|---|---|---|---|---|---|---|---|
| -OXYGEN | 1.078 | | 0.034 | MOL | | 1.78 | % | 1.78 | % |
| -NITROGEN | 17.859 | | 0.638 | | | 33.74 | % | 33.74 | % |
| -WATER | 20.710 | 15.982 | 1.149 | | 0.61 | 60.81 | % | | |
| -CO2 | 3.049 | | 0.069 | | 0.04 | 3.67 | % | 3.67 | % |
| -CO | 0.004 | | 0.000 | | | 132.89 | PPMV | 132.89 | PPMV |
| -HYDROGEN | 0.000 | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -CH4 | 0.000 | | 0.000 | | | 1.50 | PPMV | 1.50 | PPMV |
| -HCl | 0.000 | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -NO | 0.000 | | 0.000 | | | 14.26 | PPMV | 14.26 | PPMV |
| -SO2 | 0.000 | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -SO3 | 0.000 | | 0.000 | | | 0.00 | PPMV | 0.00 | PPMV |
| -ASH | 0.000 | | | | | 100.01 | | 39.20 | |
| TOTAL | | 42.700 | 1.890 | | | 22.59 | | | |
| | | 100.000% | | | | MOL WT | | | |

| EXIT ENTHALPIES | BTU/LB FUEL | | |
|---|---|---|---|
| -OXYGEN | 92.7 | | |
| -NITROGEN | 1699.6 | | |
| -WATER | 3591.7 | | |
| -CO2 | 260.8 | | |
| -CO | 0.1 | | |
| -HYDROGEN | 0.0 | | |
| -CH4 | 0.0 | | |
| -HCl | 0.0 | | |
| -NO | 0.0 | | |
| -SO2 | 0.0 | | |
| -SO3 | 0.0 | | |
| -ASH | 0.0 | | |
| TOTAL | | 22,415 | |
| | | | 0.00 |

**RECYCLE FLUE GAS:**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| INLET FLUE GAS TEMPERATURE | 461 F | | | | VOL PCT WET | | |
| FLUE GAS RECIRC FLOW | LB COMP/LB FLUE | | | | | | |
| -OXYGEN | 0.025 | 0.02 | 0.001 MOL | | 1.78 % | 1.78% | -1.27E-05 |
| -NITROGEN | 0.418 | 0.36 | 0.015 | | 33.74 % | 33.74% | -2.61E-04 |
| -WATER | 0.485 | 0.423 | 0.027 | | 60.82 % | 60.81% | -1.20E-02 |
| -CO2 | 0.071 | 0.06 | 0.002 | | 3.67 % | 3.67% | -1.08E-02 |
| | 1.000 | 0.871 | 0.044 | | 100.000 | | |
| | | | 22.6 MOL WT | | | | |
| | 5.11 | | | 5.11 | 3.00 | | |

| | | | |
|---|---|---|---|
| THETA FUNCTN FOR CP | | | |
| SPECIFIC HEATS | | | |
| -OXYGEN | 0.226 BTU/LB O2-R | 2.267 | 1.790 |
| -NITROGEN | 0.250 BTU/LB N2-R | 3.918 | 3.390 |
| -WATER | 0.455 BTU/LB WTR-R | 2.547 | 1.584 |
| -CO2 | 0.225 BTU/LB CO2-R | 0.889 | 0.414 |

| | | |
|---|---|---|
| INLET ENTHALPIES | BTU/LB FUEL | |
| -OXYGEN | 2.2 | |
| -NITROGEN | 39.8 | |
| -WATER | 84.1 | |
| -CO2 | 6.1 | |
| | | 132.2 |

FLUE GAS TO AIR MASS RATIO 23% LB FLUE/LB AIR

**FD FAN INLET:**

| | |
|---|---|
| AIR FLOW | 20.48 LB AIR/LB FUEL |
| FLUE GAS FLOW | 4.77 LB FLUE/LB FUEL |
| TOTAL INLET FLOW | 25.25 LB TOTAL/LB FUEL |
| ENTHALPY OF AIR | -185.40 BTU/LB FUEL |
| ENTHALPY OF FLUE GAS | 630.81 BTU/LB FUEL |
| TOTAL INLET ENTHALPY | 445.42 BTU/LB FUEL |

CORRECTED TO 3% O2
3.00

193.66

2.19

20.79

| | |
|---|---|
| INLET FLUE GAS TEMPERATURE | 147 F |
| (AIR+FLUE GAS) FLOW | LB COMP/LB FUEL |
| -OXYGEN | 4.831 |
| -NITROGEN | 17.494 |
| -WATER | 2.580 |
| -CO2 | 0.341 |
| | 25.246 |

| | | | | |
|---|---|---|---|---|
| THETA FUNCTN FOR CP | 3.37 | | 3.37 | 3.00 |
| SPECIFIC HEATS | | | | |
| -OXYGEN | 0.220 | BTU/LB O2-R | 1.872 | 1.790 |
| -NITROGEN | 0.249 | BTU/LB N2-R | 3.482 | 3.390 |
| -WATER | 0.448 | BTU/LB WTR-R | 1.750 | 1.584 |
| -CO2 | 0.206 | BTU/LB CO2-R | 0.491 | 0.414 |

| | | |
|---|---|---|
| INLET ENTHALPIES | BTU/LB FUEL | |
| -OXYGEN | 71.3 | |
| -NITROGEN | 292.0 | |
| -WATER | 77.4 | |
| -CO2 | 4.7 | |
| | | 445.4 |

[redacted]

| | |
|---|---|
| | CORRECTED TO 3% O2 |
| | 3.00 |
| | 193.66 |
| | 2.19 |
| | 20.79 |

# APPENDIX F

## Macros Reference

```
'
' TESTDATA Macro
  Macro recorded 2/17/2002 by Ravi Chandran

'
 ublic itindex As Integer
.rivate Const itmax As Integer = 10
Private Const ref1 As String = "B500"
    Option Explicit
    Option Base 1
    Dim ITERTN1 As Integer, ITERTN2 As Integer
    Dim flag1 As Integer

 ub TESTDATA()

    Range("J451").Select
    Selection.Copy
    Range("G512").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("D451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G513").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("F451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G514").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("G451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G519").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("H451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G520").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("I451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G521").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("M451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G522").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("N451").Select
    Application.CutCopyMode = False
    Selection.Copy
    Range("G523").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=False
    Range("R451:V451").Select
    Application.CutCopyMode = False
    Selection.Copy
```

```
    Range("G528").Select
    Selection.PasteSpecial Paste:=xlValues, Operation:=xlNone, SkipBlanks:= _
        False, Transpose:=True
    Application.Run Macro:="SOLVER"
 nd Sub

'
  SOLVER Macro
  Macro recorded 2/17/2002 by Ravi Chandran
'

 ub SOLVER()
    itindex = 0
    For ITERTN1 = 1 To itmax
    flag1 = Range("D560").Value
    If flag1 > 0 Then Exit Sub
    Range("C539").Select
    Range("C539").GoalSeek Goal:=0, ChangingCell:=Range("G539")
    Range("C540").Select
    Range("C540").GoalSeek Goal:=0, ChangingCell:=Range("G540")
    Range("C541").Select
    Range("C541").GoalSeek Goal:=0, ChangingCell:=Range("G541")
    Range("C542").Select
    Range("C542").GoalSeek Goal:=0, ChangingCell:=Range("G542")
    Range("C543").Select
    Range("C543").GoalSeek Goal:=0, ChangingCell:=Range("G543")
    Range("C548").Select
    Range("C548").GoalSeek Goal:=0, ChangingCell:=Range("G548")
    Range("C549").Select
    Range("C549").GoalSeek Goal:=0, ChangingCell:=Range("G549")
    Next ITERTN1
End Sub
```

```
Sub Recycle()
'
' Recycle Macro
' Macro recorded 2/18/2002 by Ravi Chandran
'
' Keyboard Shortcut: Ctrl+Shift+A
'
    Range("D232").GoalSeek Goal:=0, ChangingCell:=Range("B177")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q38").Select
    Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
    Range("Q36").Select
    Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q38").Select
    Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
    Range("Q37").Select
    Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
    Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
    Range("D232").Select
    Range("D232").GoalSeek Goal:=0, ChangingCell:=Range("B177")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q36").Select
    Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q37").Select
    Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
    Range("Q38").Select
    Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q36").Select
    Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
    Range("Q37").Select
    Range("Q37").GoalSeek Goal:=0, ChangingCell:=Range("K37")
    Range("Q38").Select
    Range("Q38").GoalSeek Goal:=0, ChangingCell:=Range("K38")
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q36").Select
    Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
    Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
    Range("Q35").Select
    Range("Q35").GoalSeek Goal:=0, ChangingCell:=Range("K35")
    Range("Q36").Select
    Range("Q36").GoalSeek Goal:=0, ChangingCell:=Range("K36")
    Application.Run "'253TUBE_TESTDATA_ANALYSIS.xls'!TESTDATA"
End Sub
```