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.
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Baltimore, Maryland 21226

Date Prepared: June 15, 2001

Date Issued of First Draft: August 17, 2001

Date Issued of Second Draft: November 30, 2001

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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:

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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 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.

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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.

<u>Project Costs</u>

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.

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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

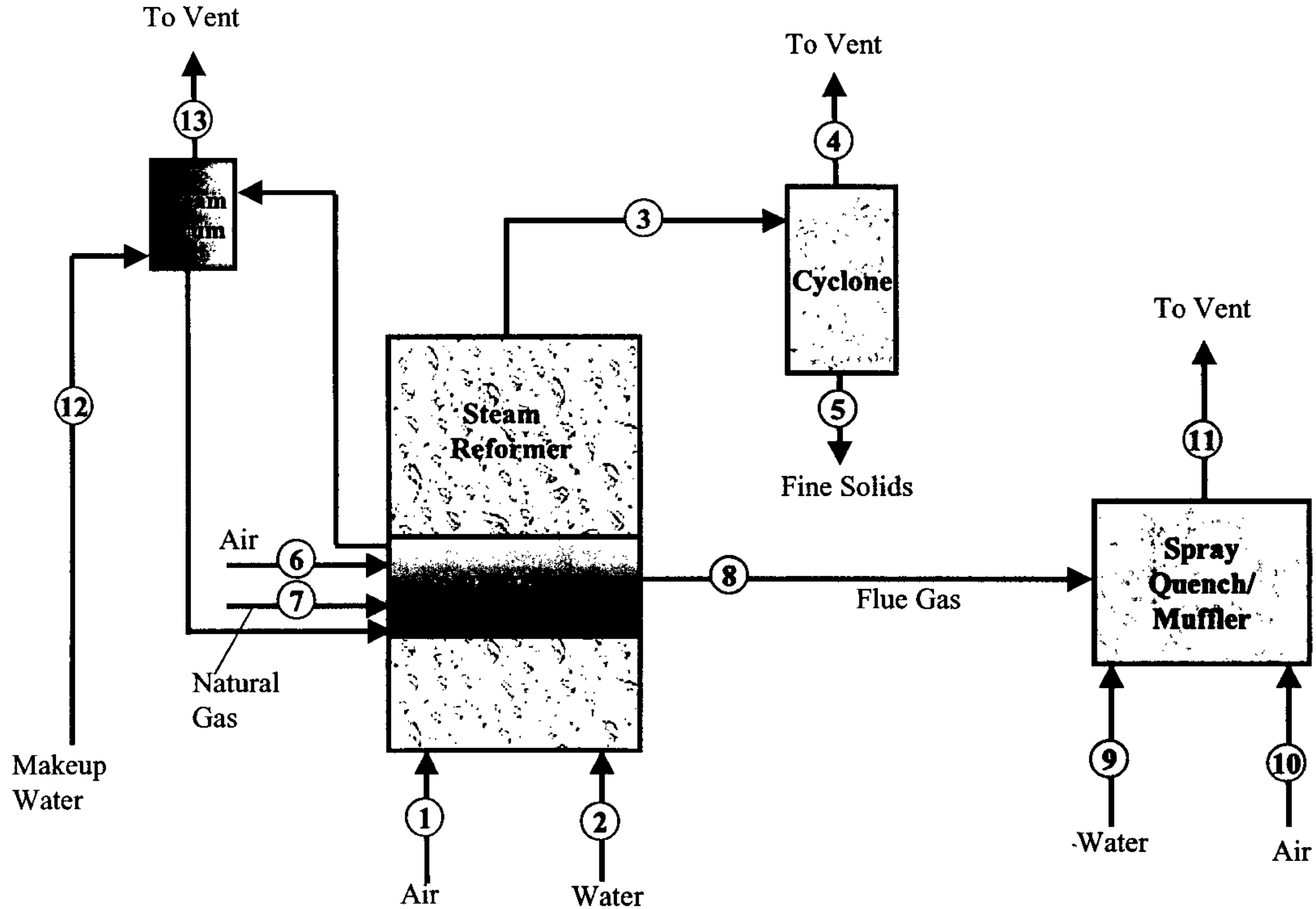


FIGURE 1-1: BLOCK FLOW DIAGRAM

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.

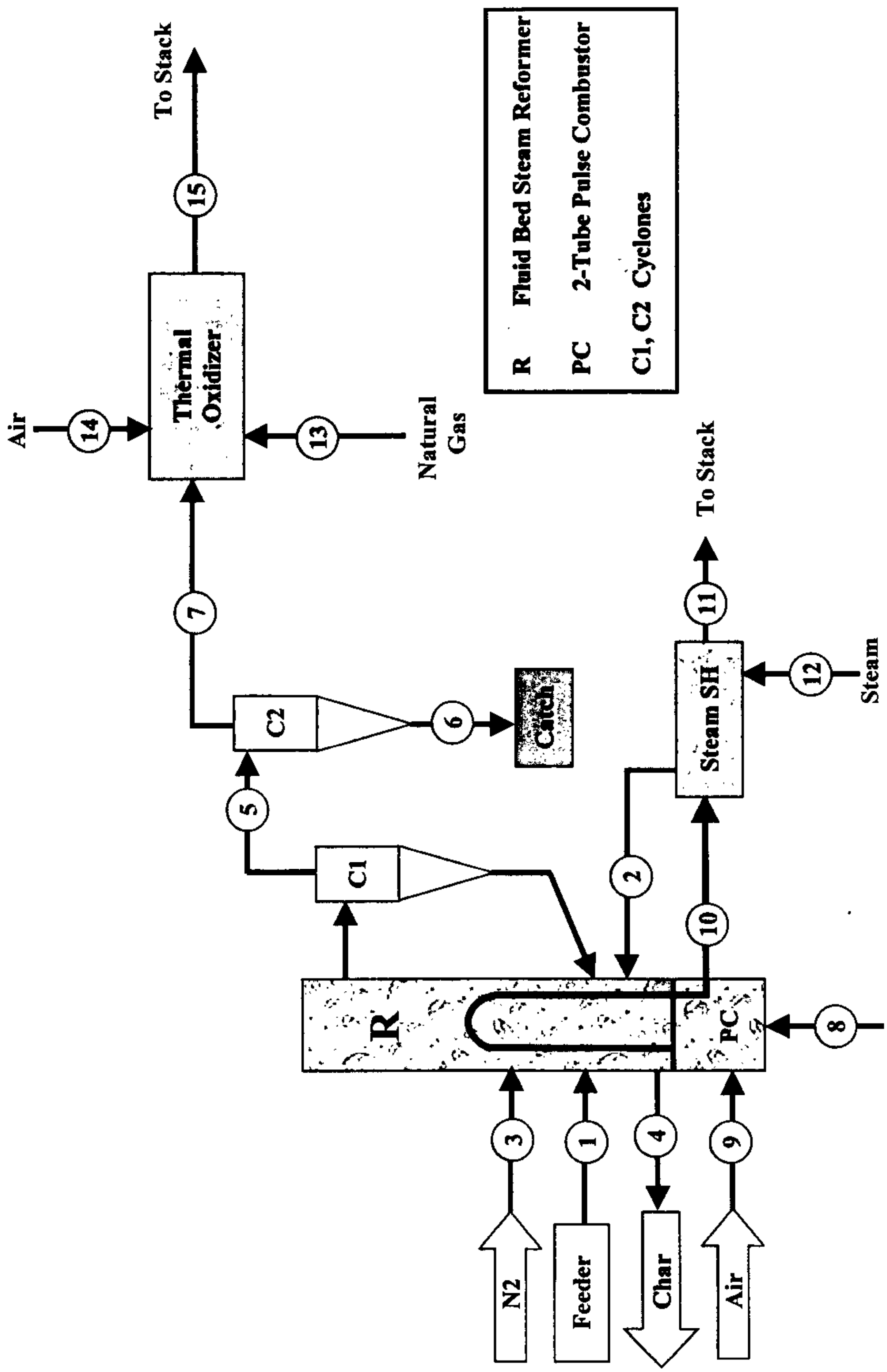


FIGURE 1-2: PDU PROCESS FLOW DIAGRAM

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

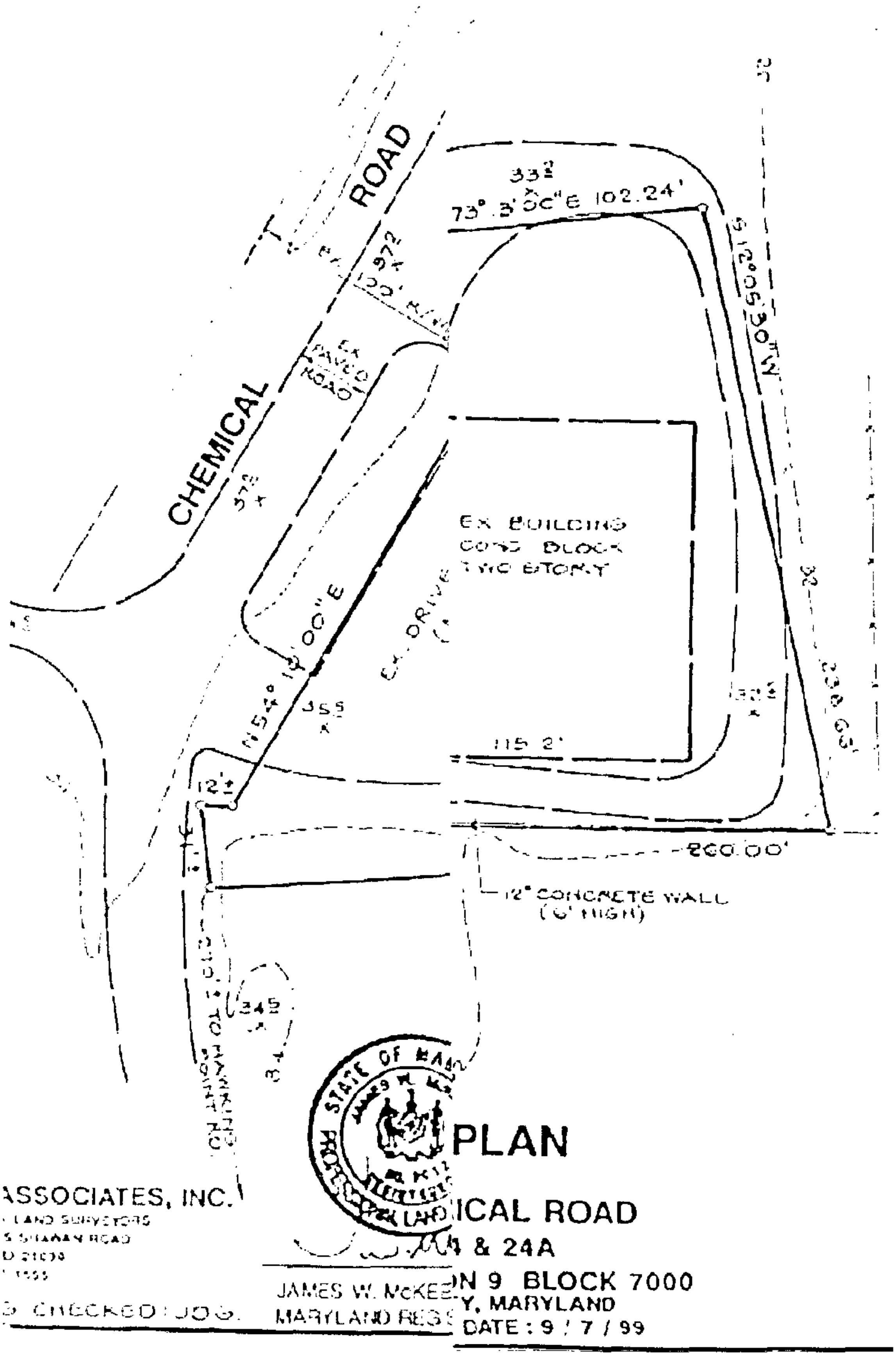
The project is located at ThermoChem's facility at 6001 Chemical Road, Baltimore, Maryland. The pulse combustor facility is in an outdoor area within the Company premises and the PDU is located indoors in the Company Development and Manufacturing plant (see Figure 1-3).

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'
200.00'
115.2'
12" CONCRETE WALL
(6' HIGH)
PLAN
ASSOCIATES, INC.
ICAL ROAD
4 & 24A
N 9 BLOCK 7000
Y, MARYLAND
DATE : 9 / 7 / 99
JAMES W. McKEE

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.

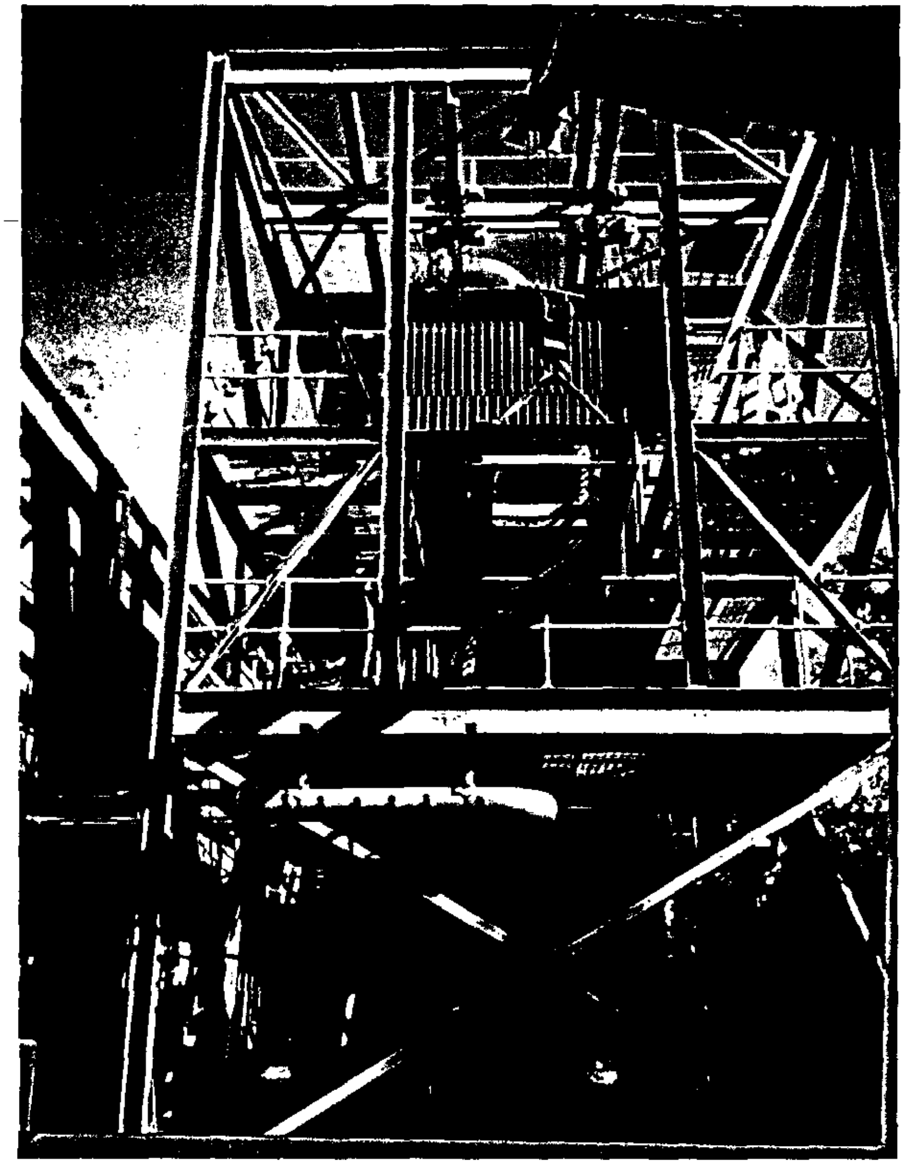


FIGURE 1-4: FULL-SCALE PULSE COMBUSTOR TEST FACILITY UNDER CONSTRUCTION

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.

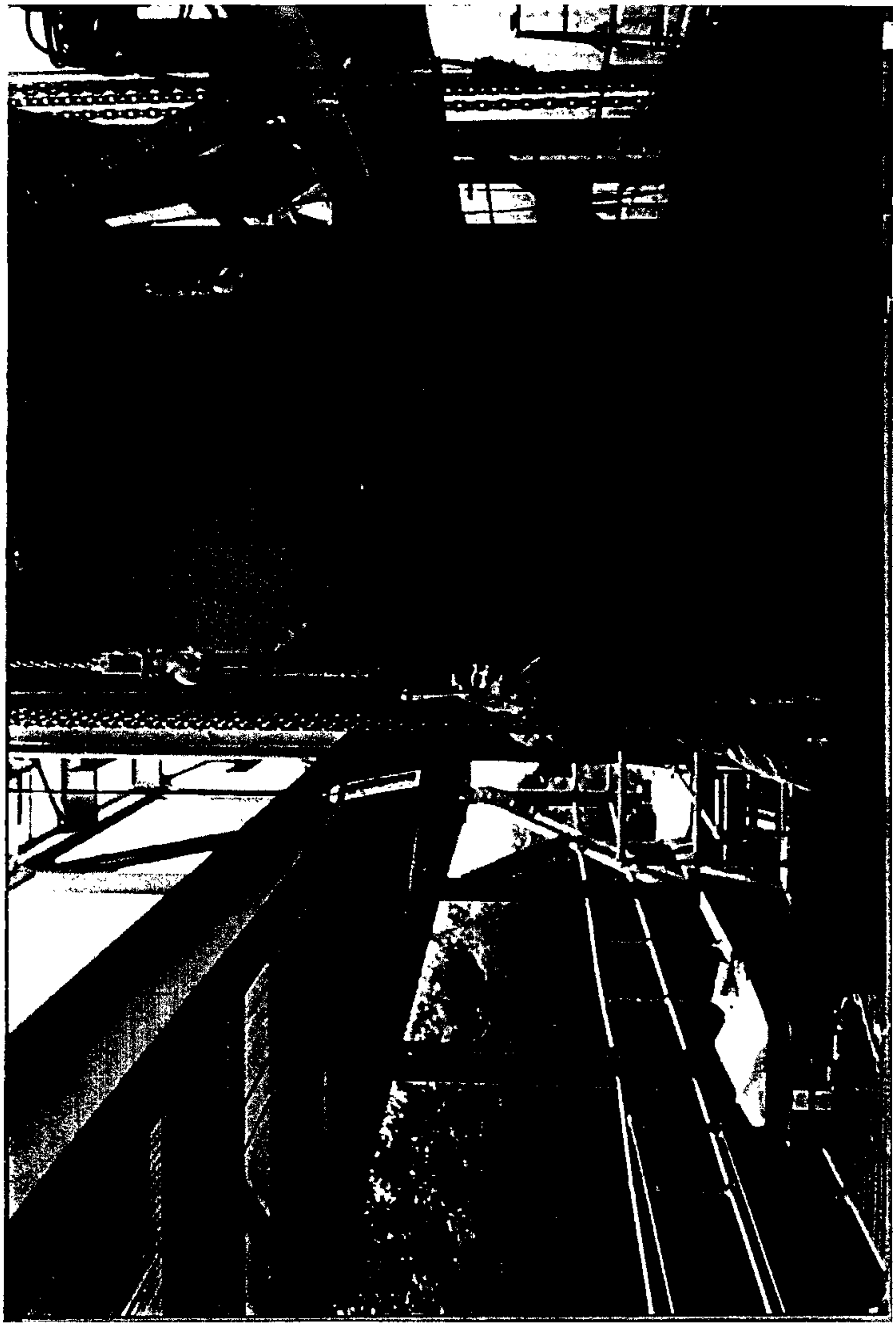


FIGURE 1-5: 253-TUBE PULSE HEATER AFTER INSTALLATION IN THE VESSEL

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

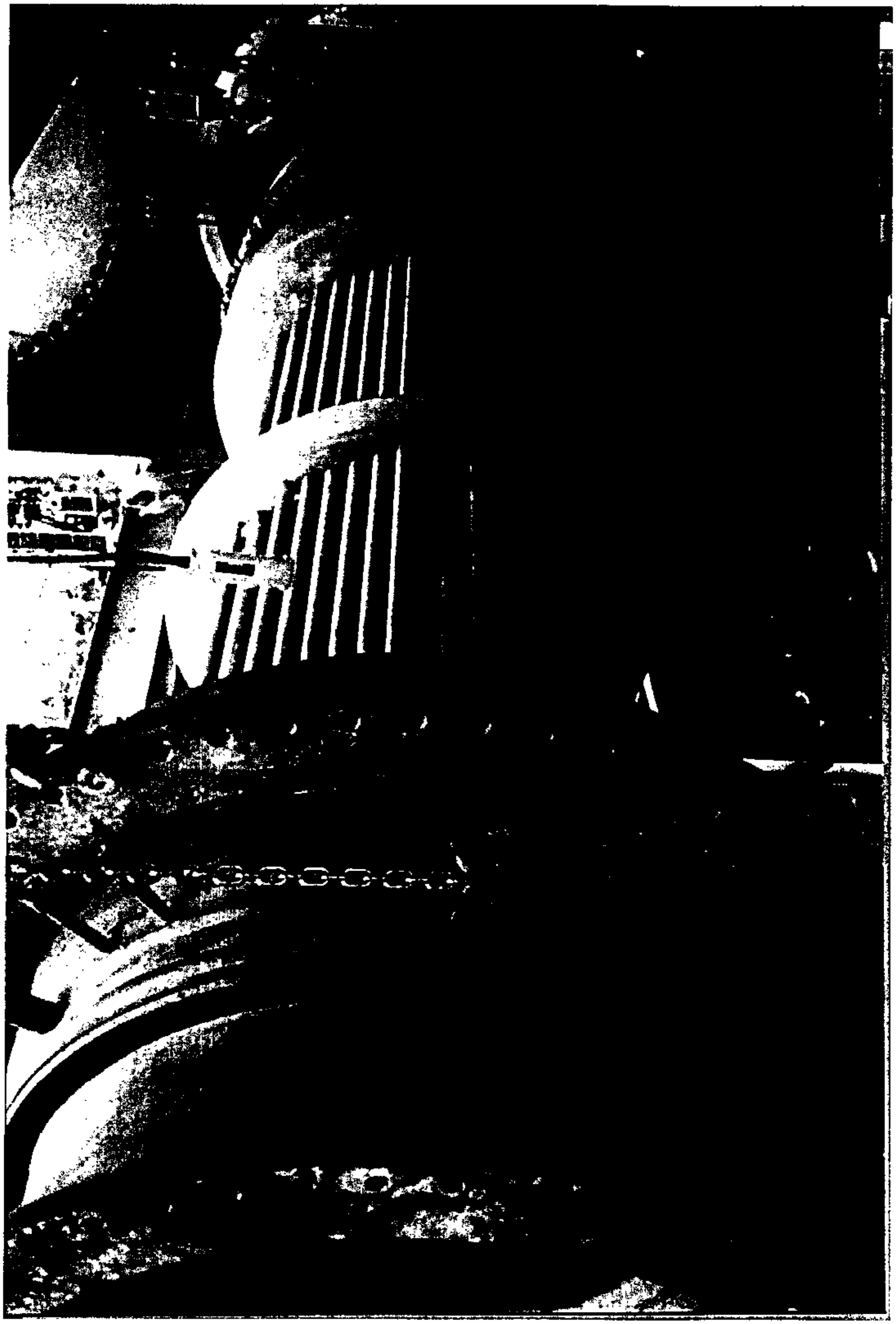


FIGURE 1-7: 253-TUBE PULSE HEATER READY FOR INSERTION

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

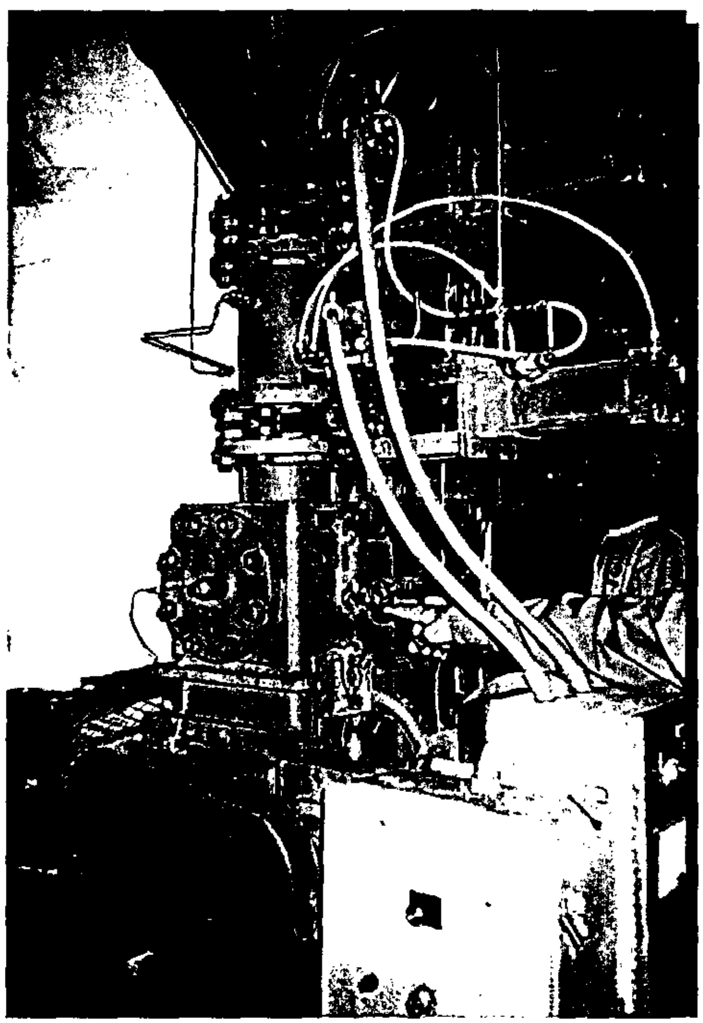


FIGURE 1-9: COAL METERING AND INJECTION

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.

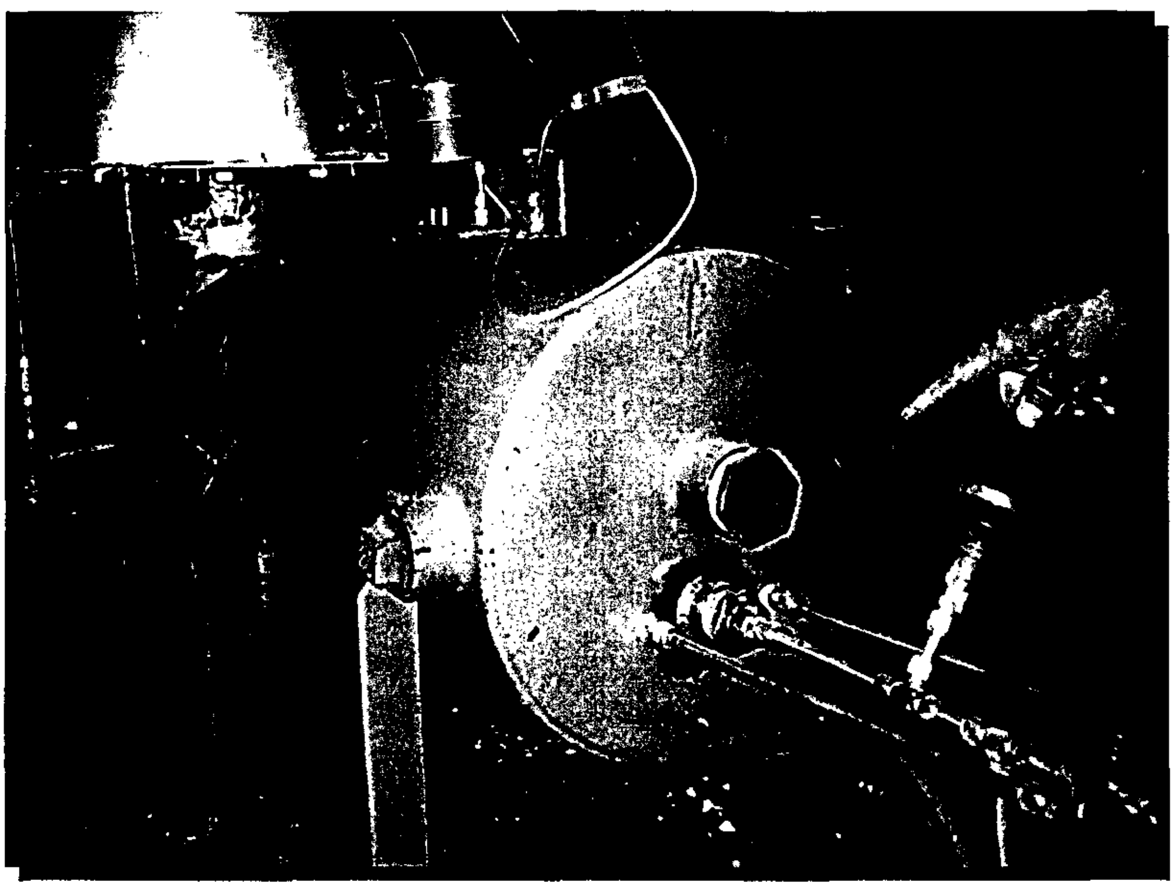


FIGURE 1-10: PULSE COMBUSTOR COMBUSTION AIR PLENUM

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

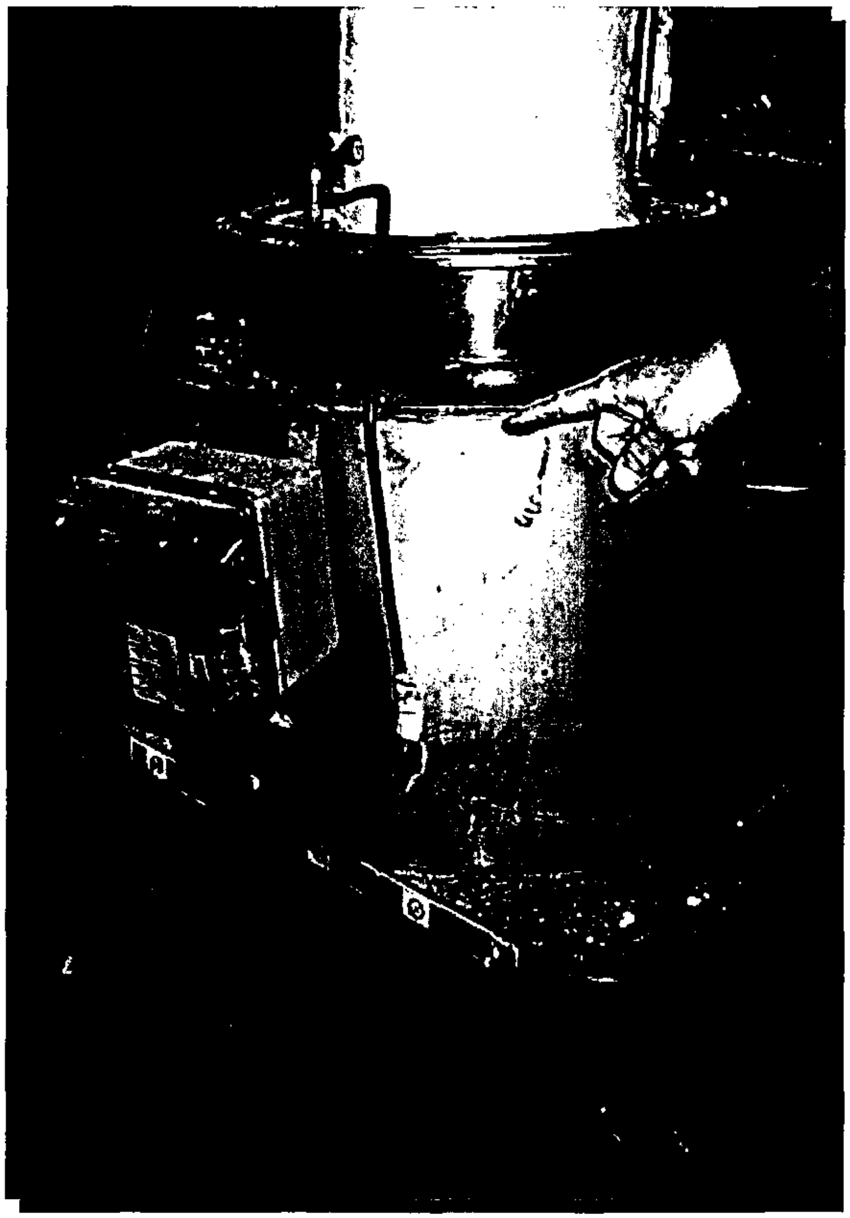


FIGURE 1-11: SECOND CYCLONE CATCH POT

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.

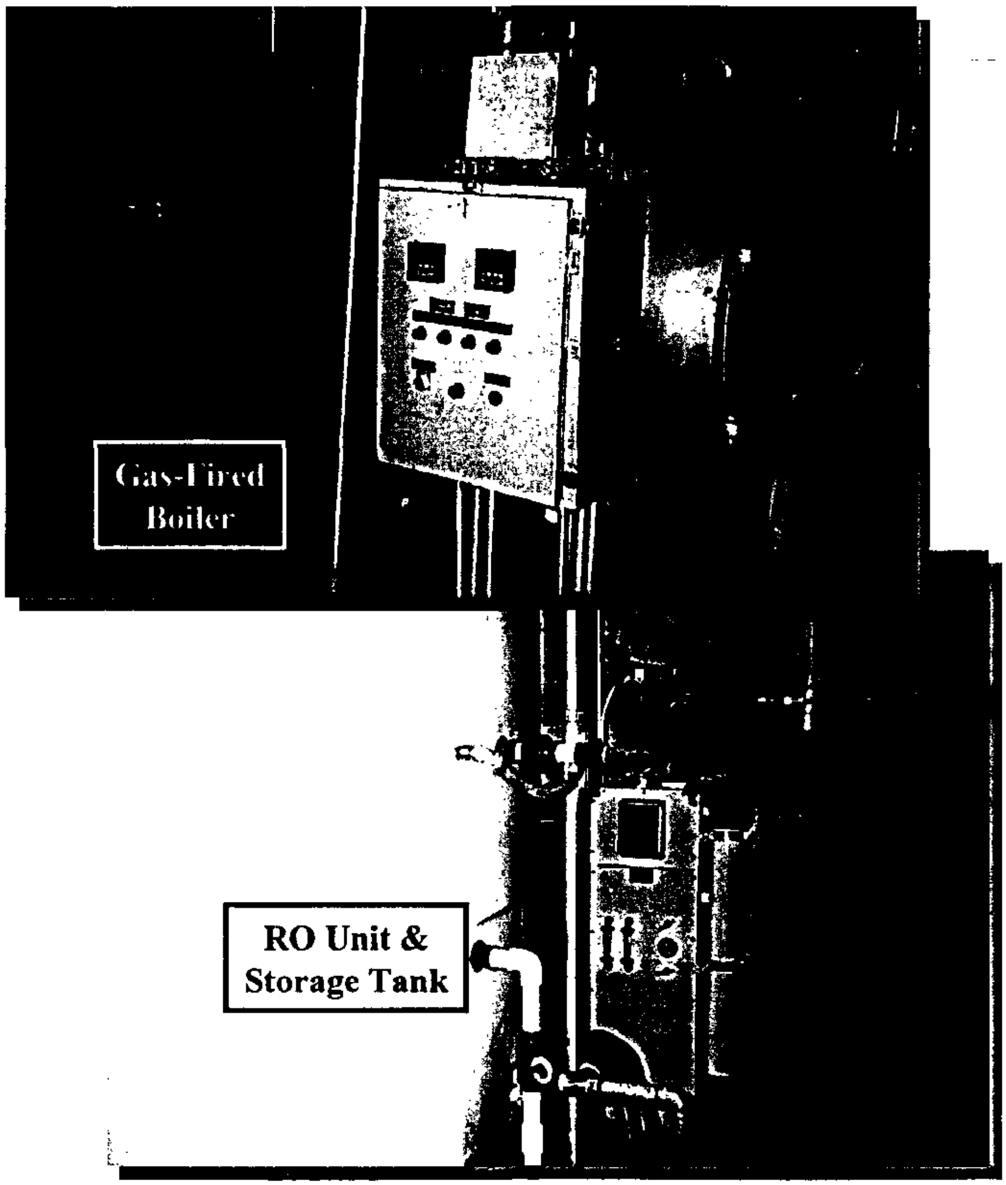


FIGURE 1-12: STEAM BOILER AND FEEDWATER RO UNIT

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.

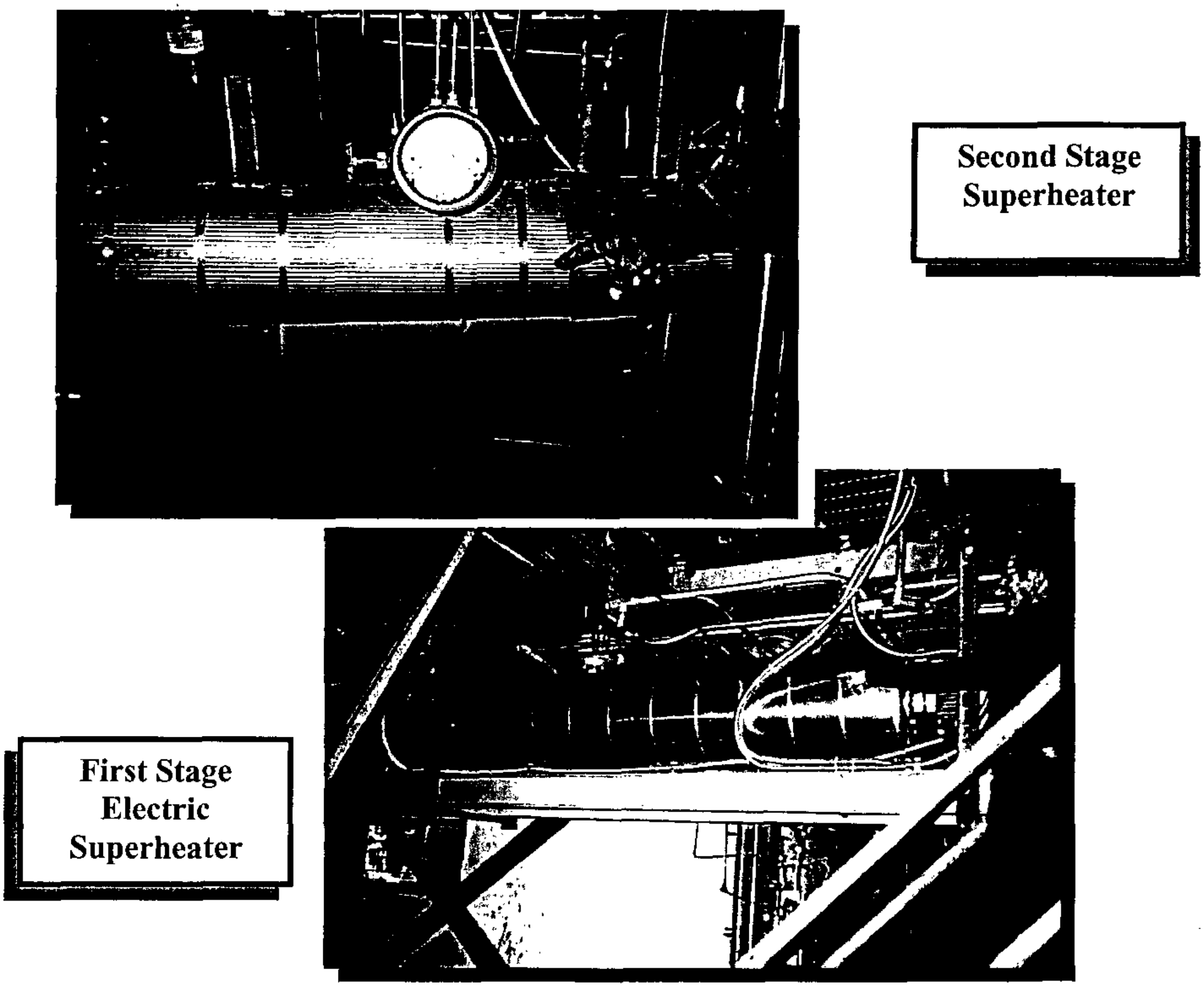


FIGURE 1-13: SUPERHEATERS

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.

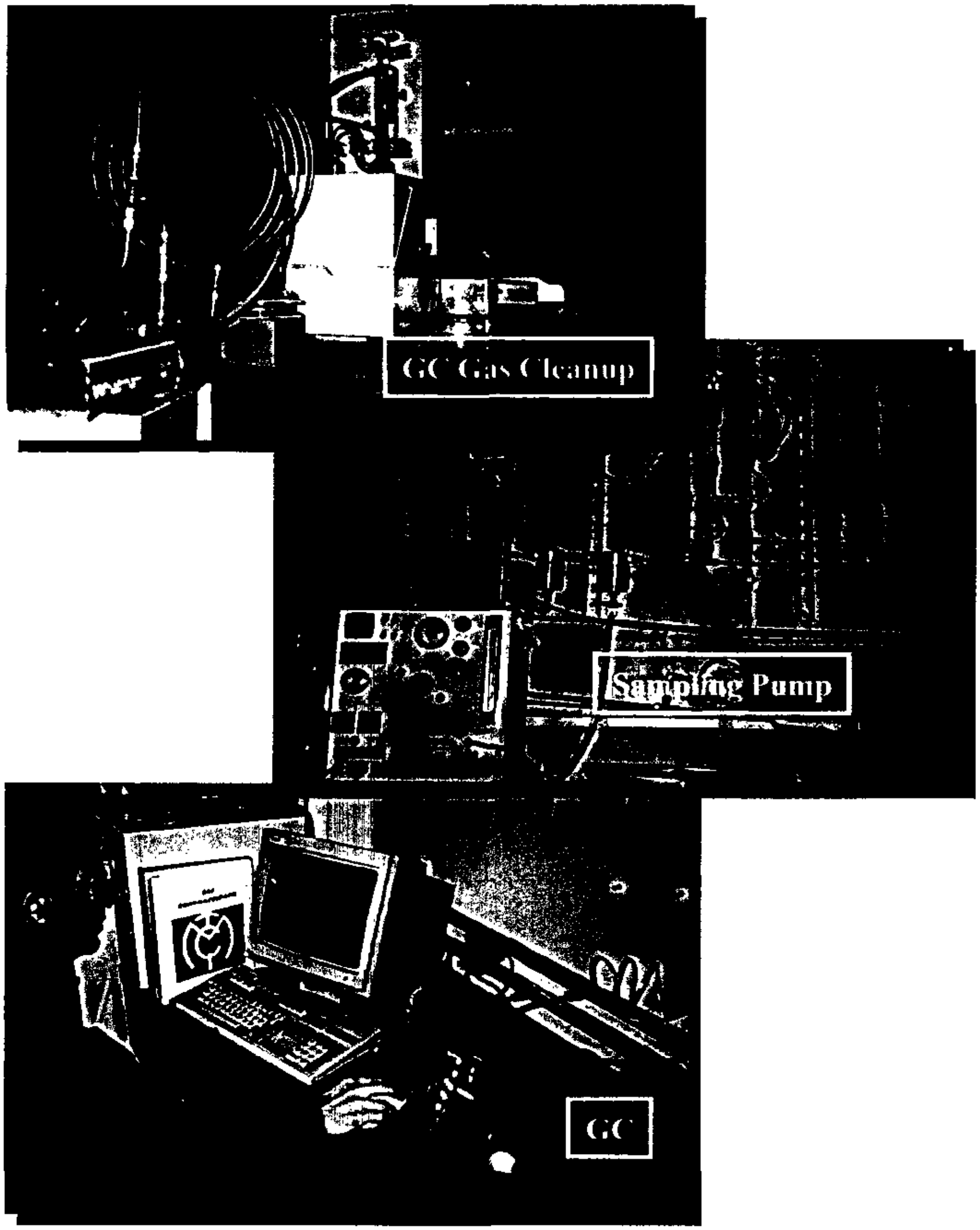


FIGURE 1-14: GAS CHROMATOGRAPH

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.

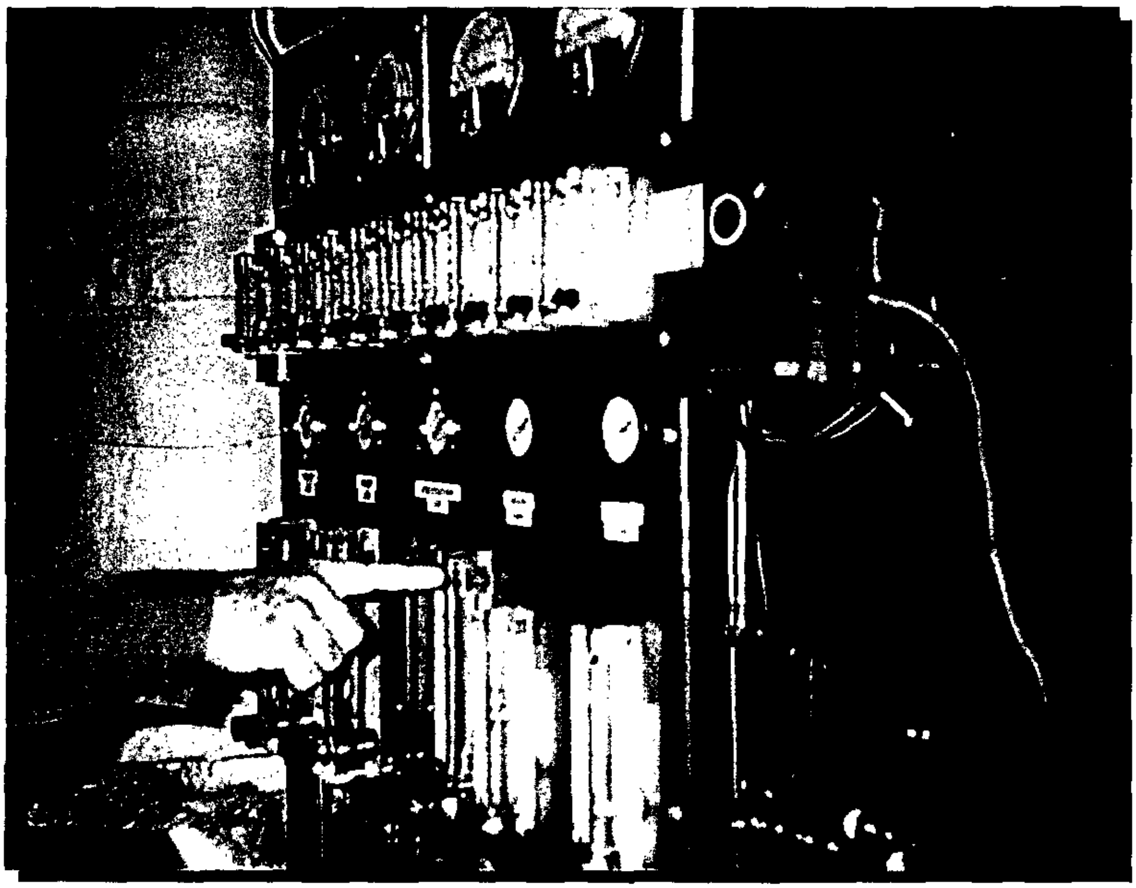


FIGURE 1-15: STEAM REFORMER CONTROLS

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.

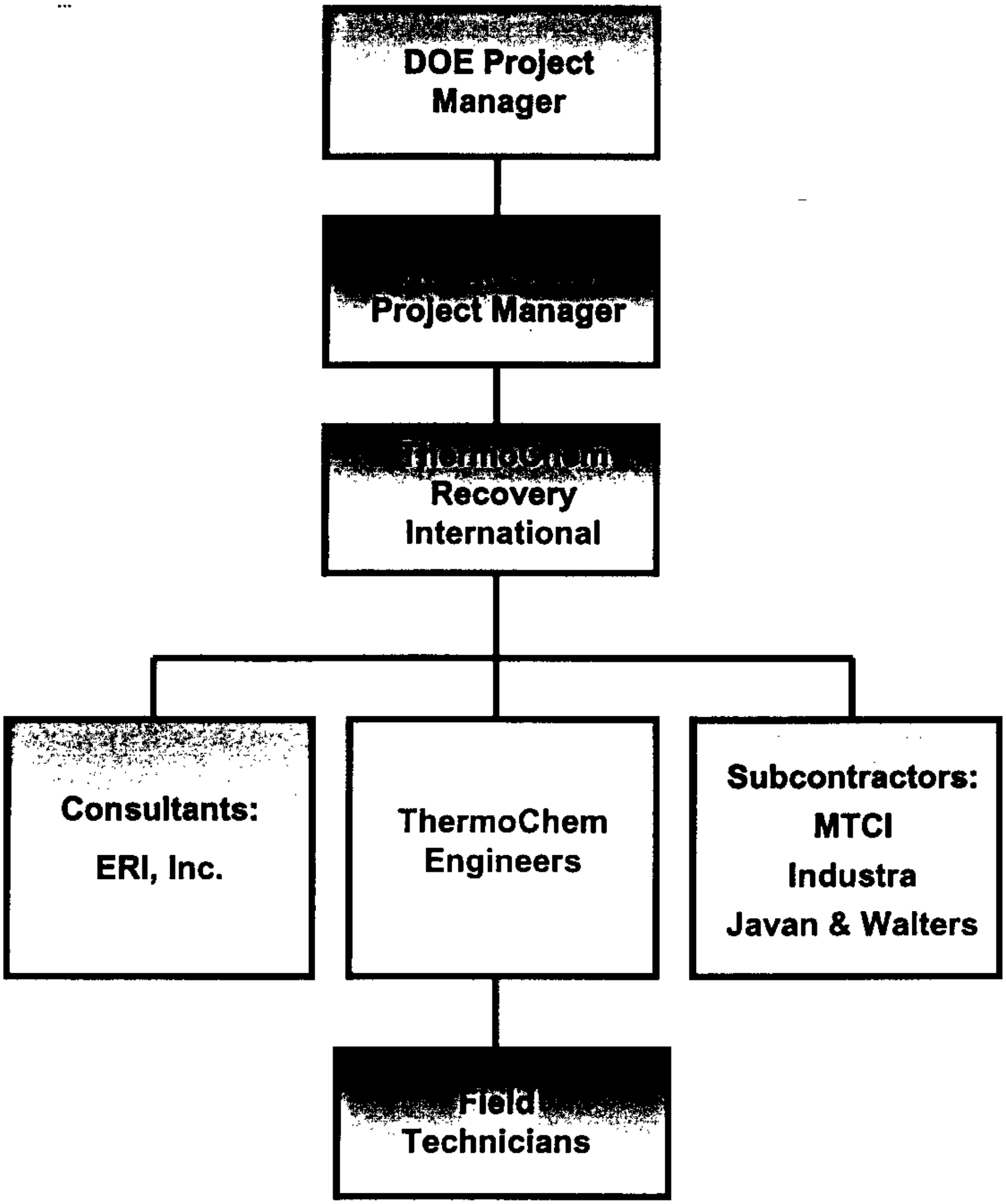


FIGURE 1-16: ORGANIZATION CHART

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 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.

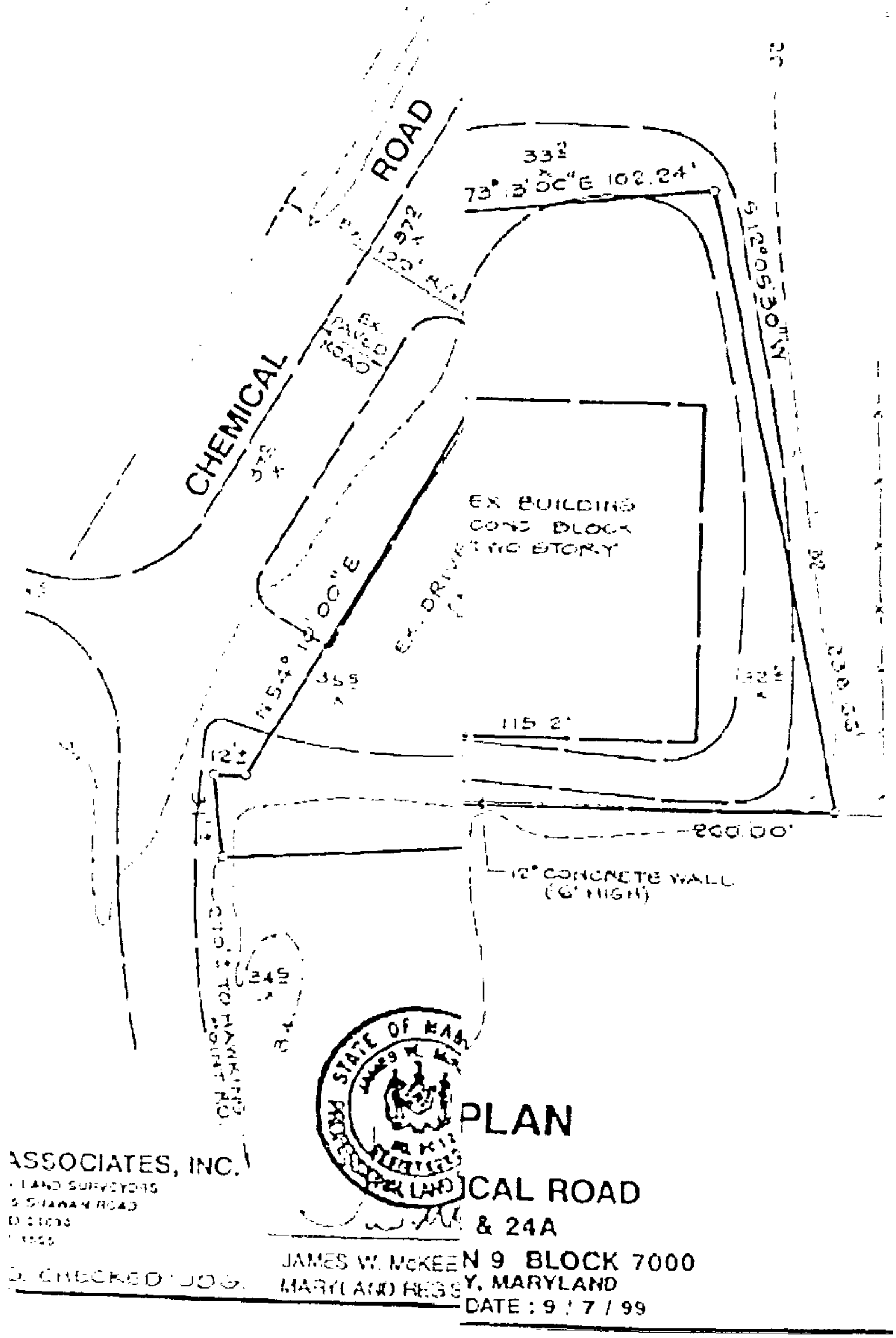
The high efficiency single stage DUCON cyclone is installed on the north side of the structure, between the structure and the existing Baltimore plant building. Solids are discharged into a drum (not shown), and hot air (with water vapor from injection of water in the bed) is vented directly from the 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

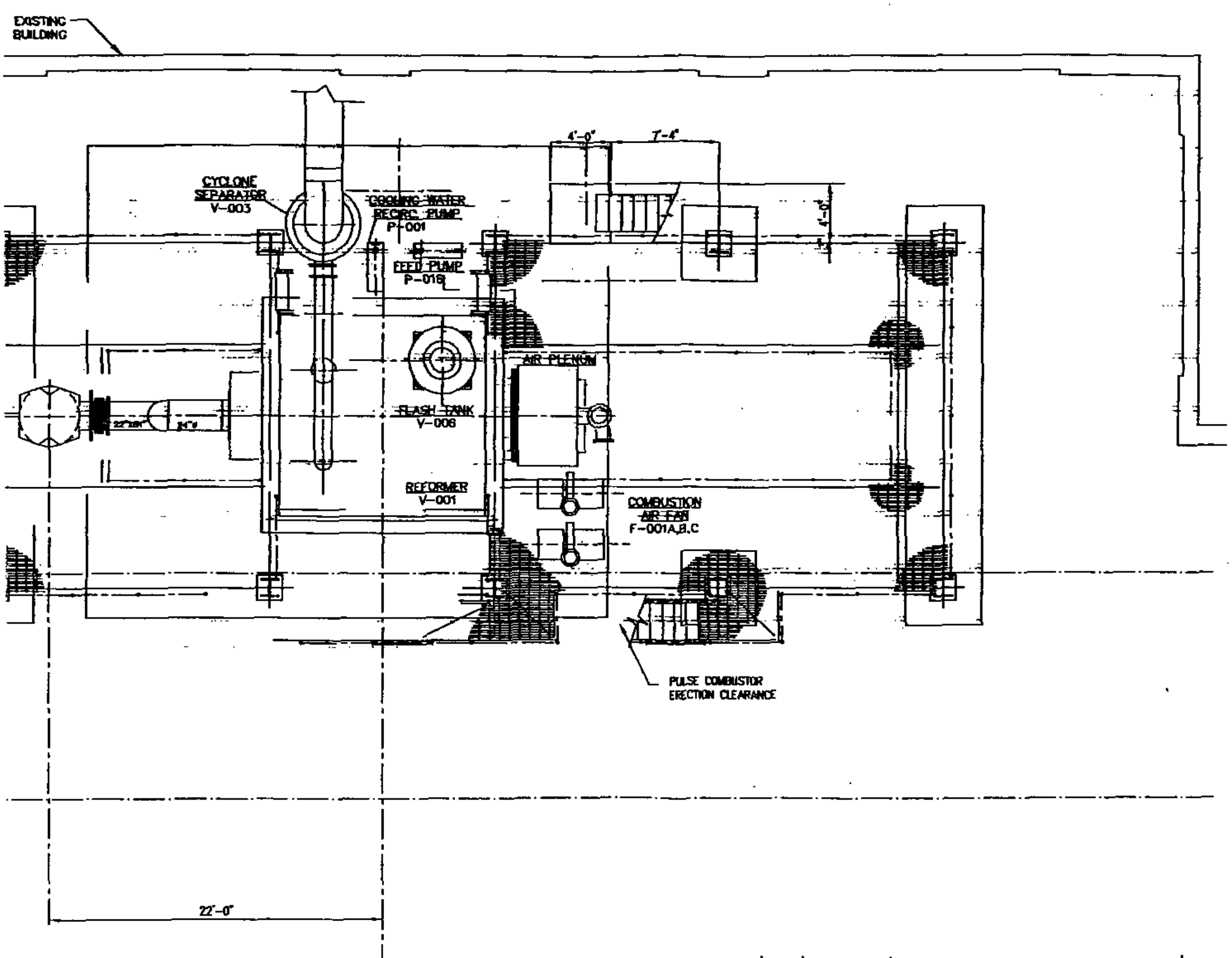
The Process Flow Diagram (PFD), the Material-Energy Balances, and the Piping and Instrumentation Diagrams (P&ID's) for the facility are presented.

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.



CHEMICAL ROAD
ROAD
73° 13' 00" E 102.24'
EX BUILDING
CONC BLOCK
TWO STORY
115.2'
200.00'
12" CONCRETE WALL (6' HIGH)
ASSOCIATES, INC.
LAND SURVEYORS
JAMES W. McKEE
MARYLAND REG
PLAN
CAL ROAD
& 24A
N 9 BLOCK 7000
Y, MARYLAND
DATE : 9 / 7 / 99



YOUT DRAWING

REV	DATE	DESCRIPTION	BY
C	13NOV98	ISSUED FOR APPROVAL	HGO
B	5NOV98	ISSUED FOR REVIEW	HGO
A	27OCT98	ISSUED FOR REVIEW	HGO

ThermoChem Inc.
6001 CHEMICAL ROAD
BALTIMORE, MD 21226

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

DEMONSTRATION PLANT
GENERAL ARRANGEMENT
SHEET 1

SCALE	DATE	DRAWING NO.	REV.
3/16"=1'-0"	29OCT98	D-11805-M-001	E
DR. BY RGP	PROJ. NO. 11805		

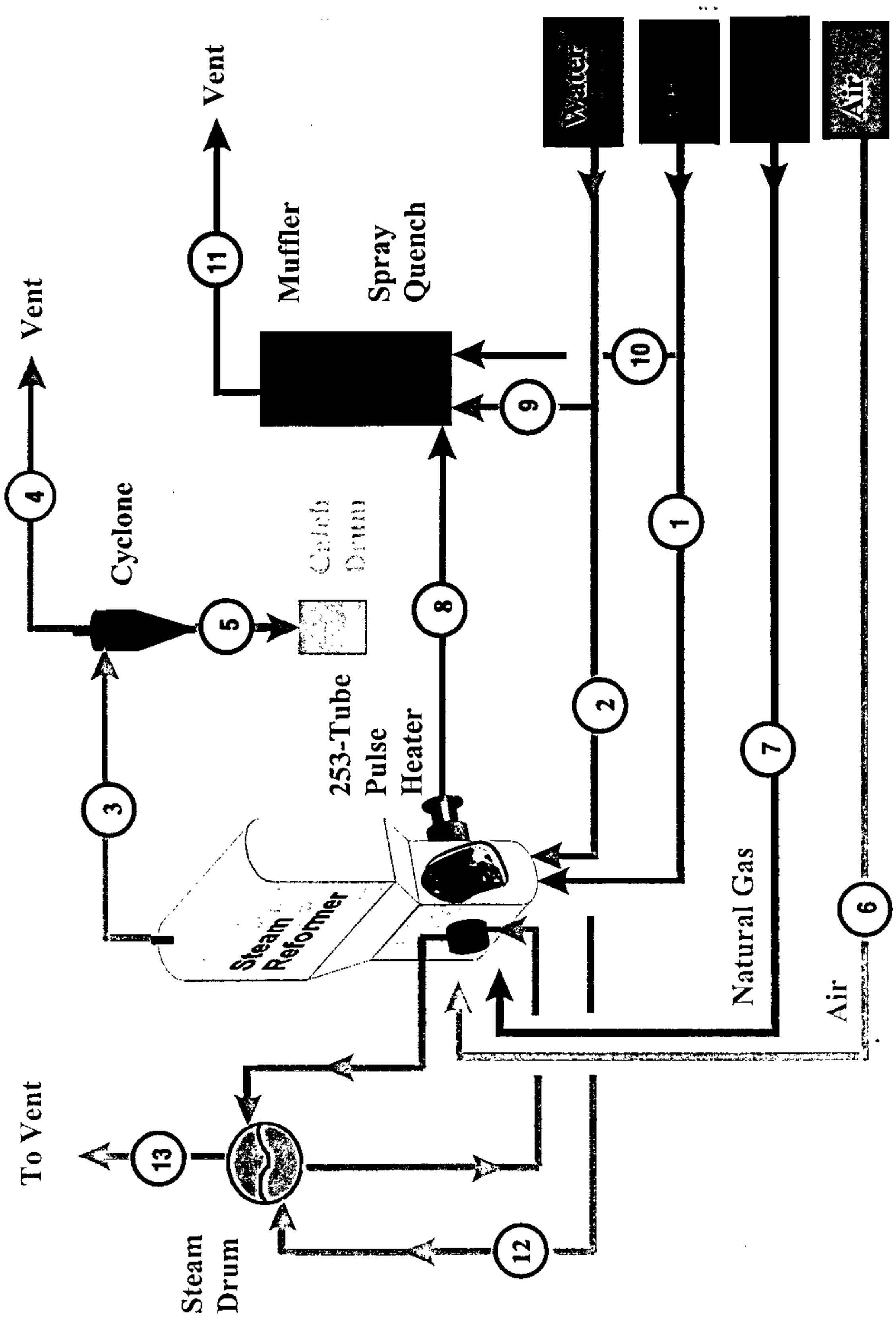


FIGURE 4-3: PROCESS FLOW DIAGRAM AND PROCESS NODES

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.

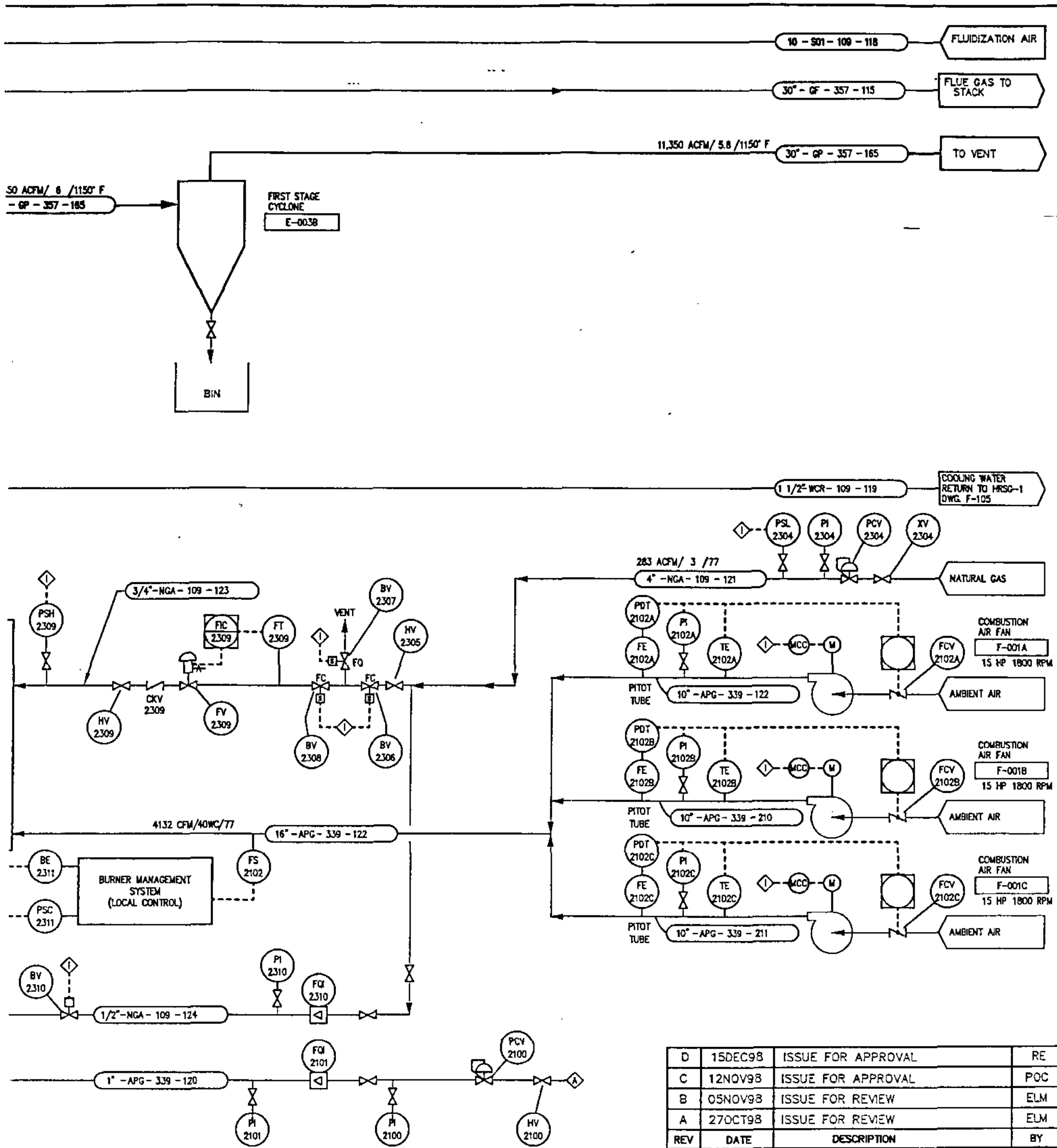
The heat load to the bed is achieved by injecting water into the sand bed to maintain the desired bed temperature at a given combustor firing rate. As shown in Figure 4-3, the water vapor (steam) leaving the cyclone with the fluidization air (node 4) is on the order of 1,800 lb/h for the firing rate 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	552	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



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

ThermoChem Inc.

6001 CHEMICAL ROAD BALTIMORE, MD 21226

NSTRUMENTATION DIAGRAMS

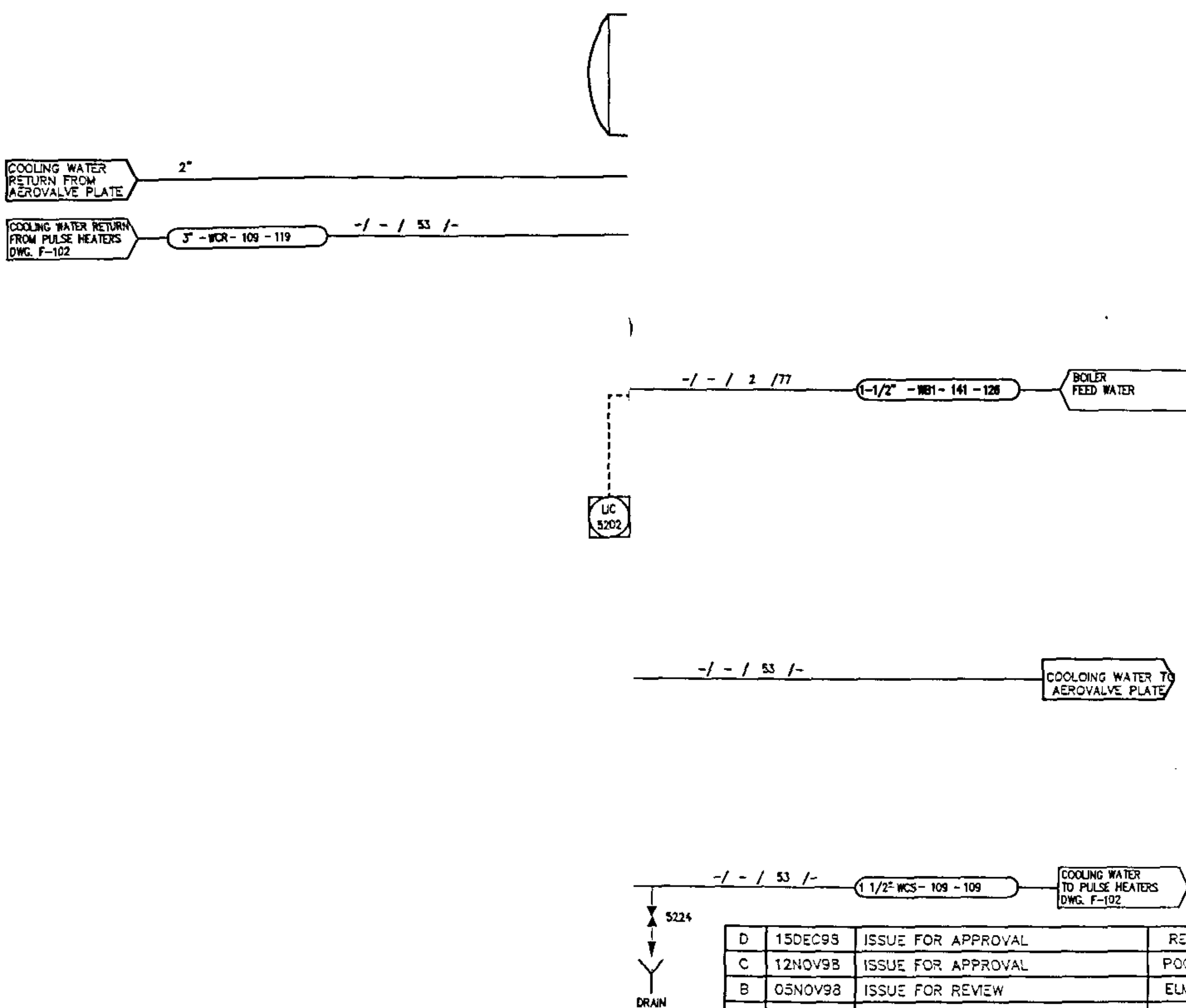
INDUSTRA
Engineers & Consultants

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

ThermoChem Inc.

6001 CHEMICAL ROAD BALTIMORE, MD 21226

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		

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 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 $\geq$ 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		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 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
000	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		Item Total Cost	Remarks
		Equipment/ Material	Installation/ Subcontract		
	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 reductant 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.

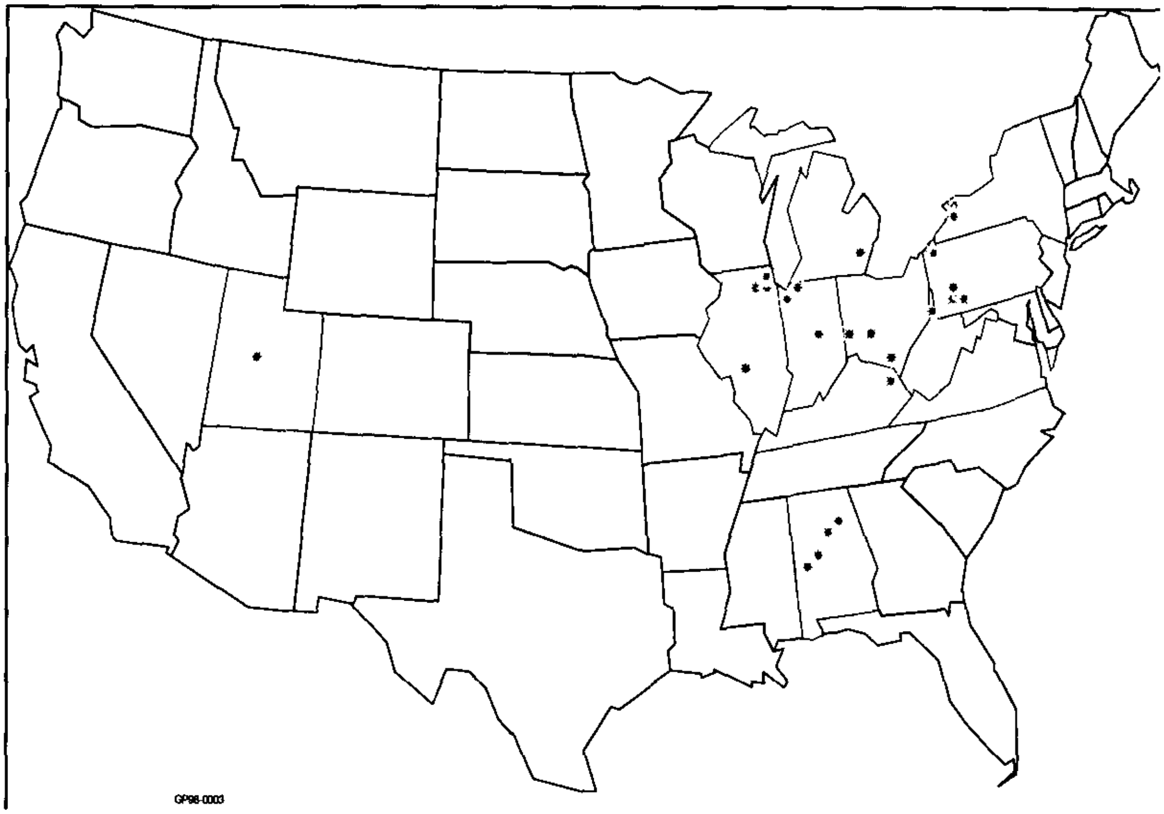


FIGURE 7-1: LOCATION OF COKE PLANTS

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).

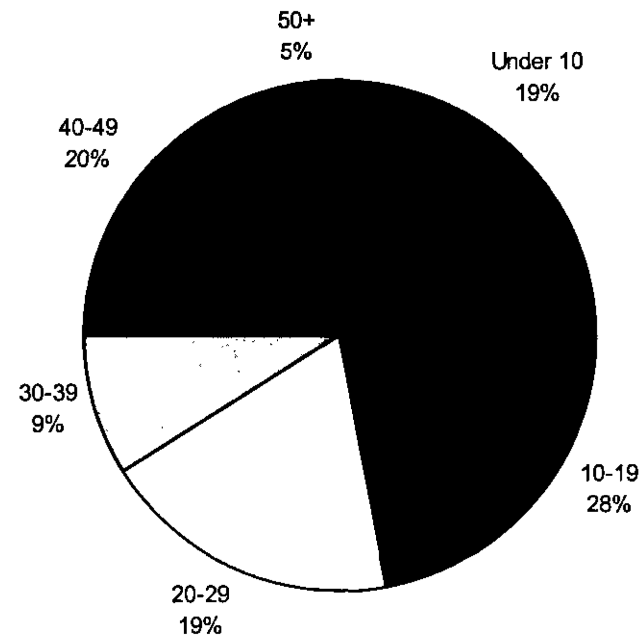
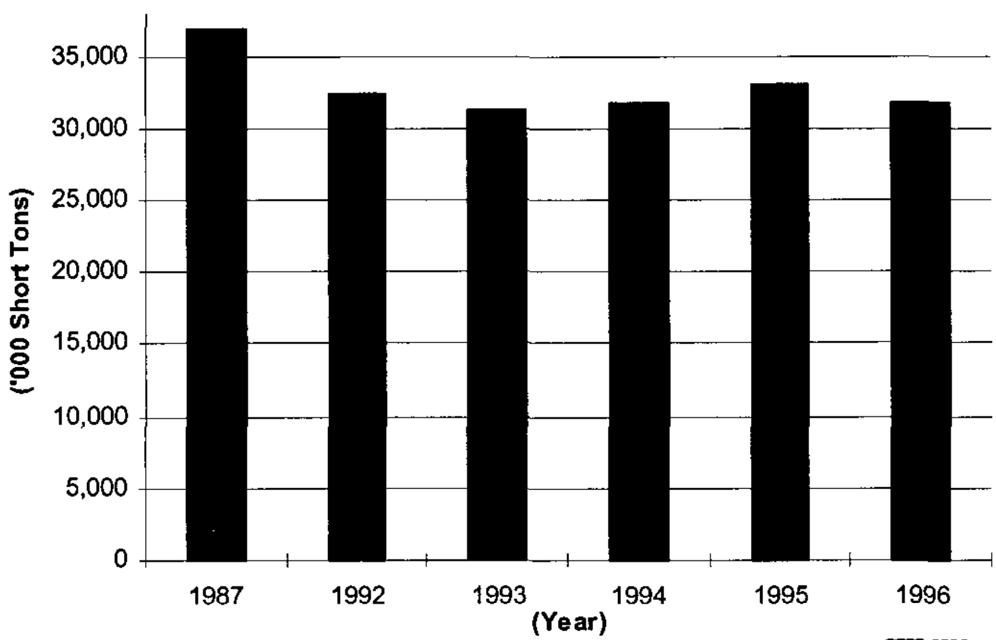


FIGURE 7-2: BATTERY AGE BY TONNAGE PER YEAR

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.

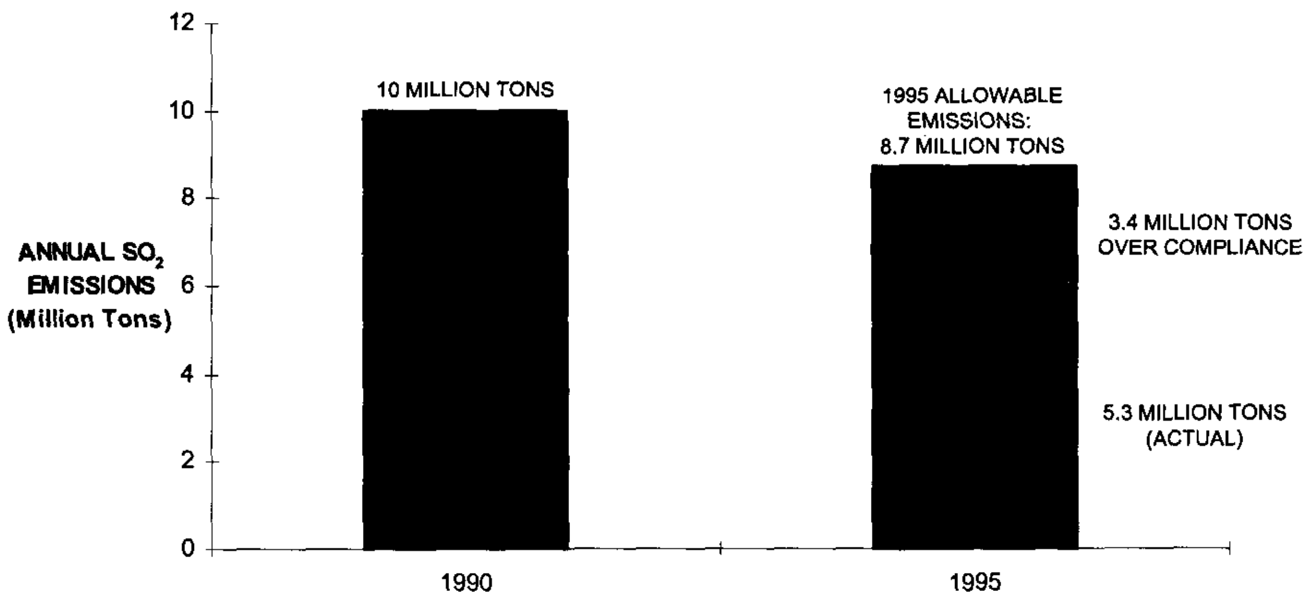
7.3 Market for Compliance Coal

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

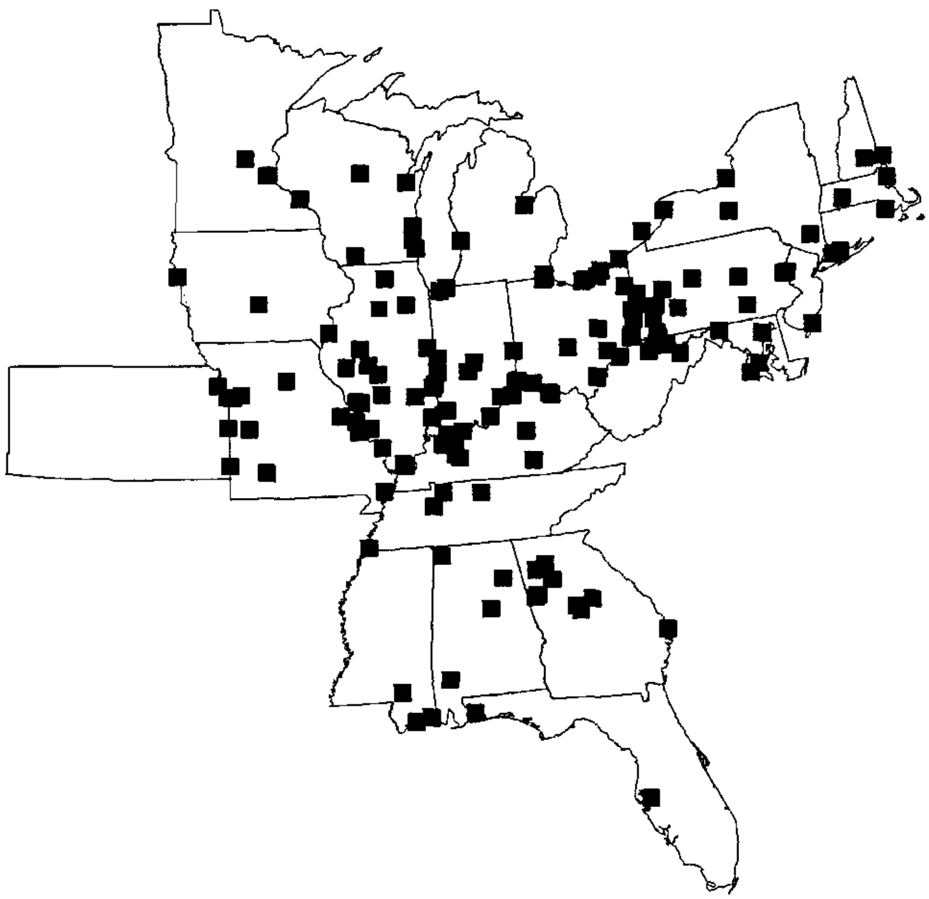
The first phase of Title IV, effective January 1, 1995, required 261 affected generating units at 110 plants to reduce their collective SO_2 emissions to 8.7 million tons (see Figure 7-4). Each "affected" unit was allocated based on its

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

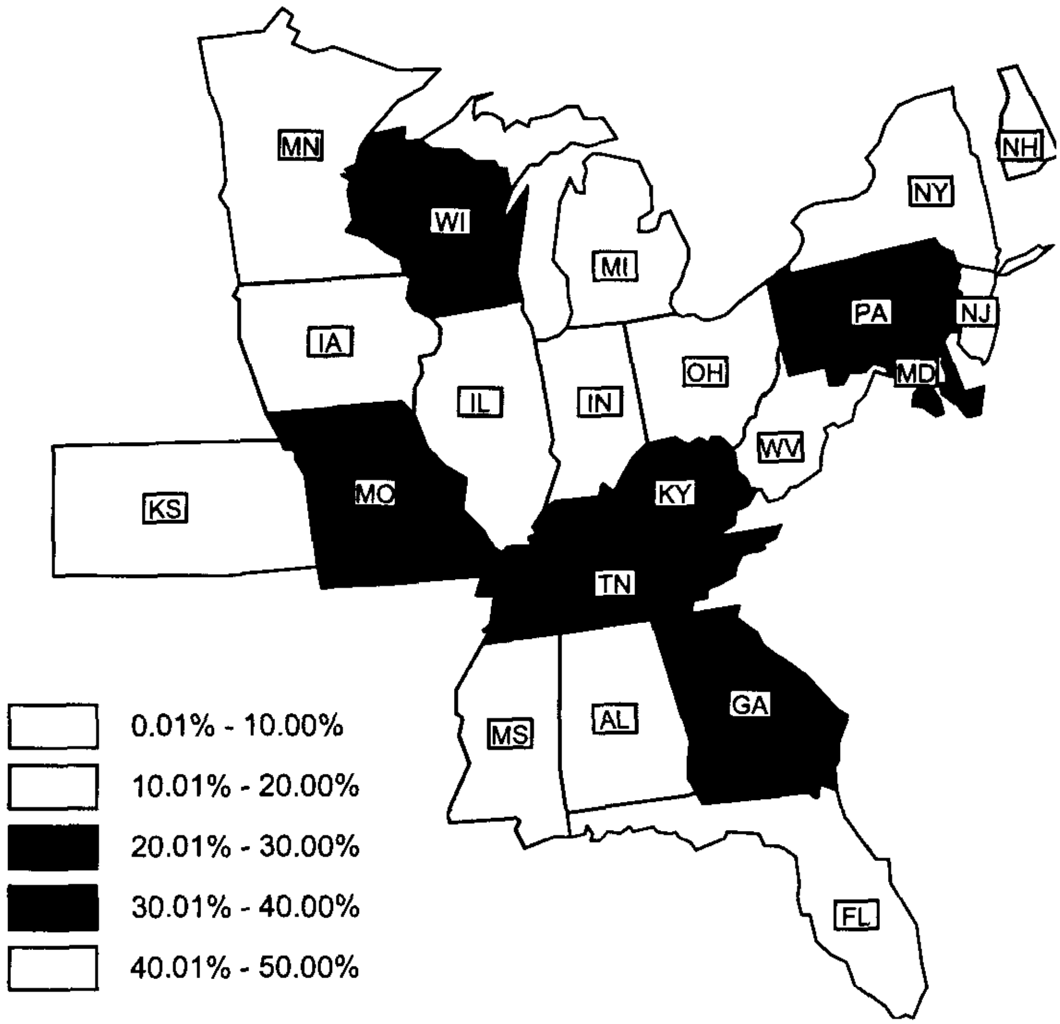
FIGURE 7-5: PHASE I AFFECTED POWER PLANTS



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)

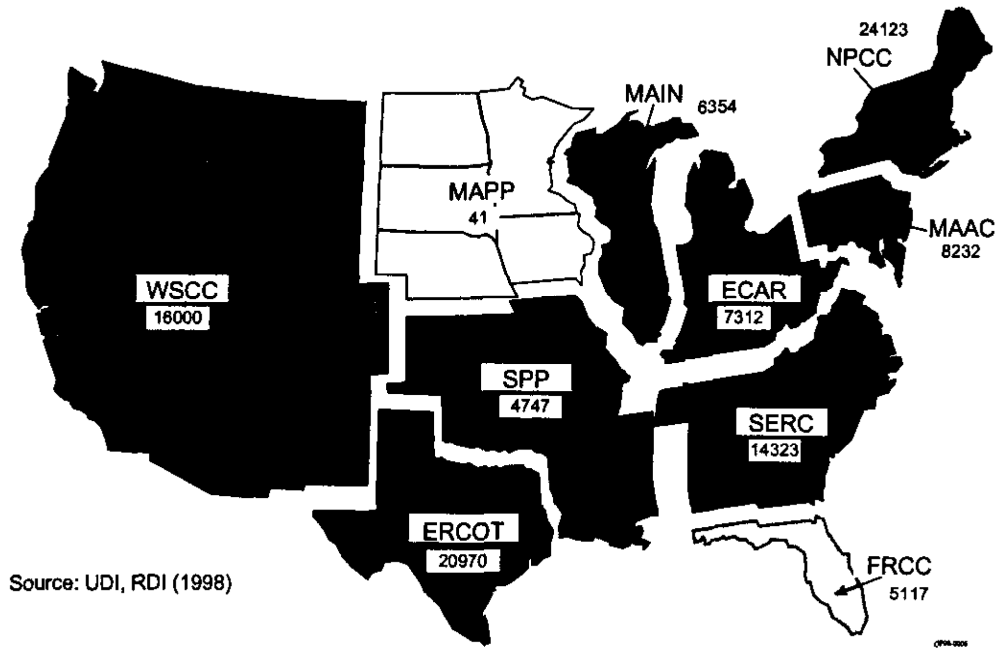
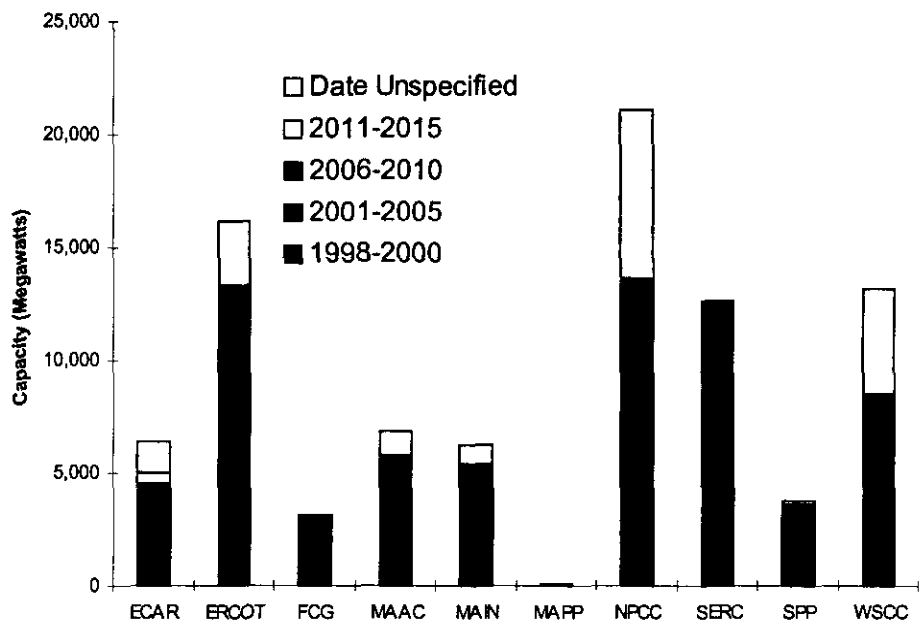


FIGURE 7-8: PROPOSED INSTALLATION DATES FOR ANNOUNCED GAS-FIRED CAPACITY ADDITIONS, BY NERC REGION (1998-2015)

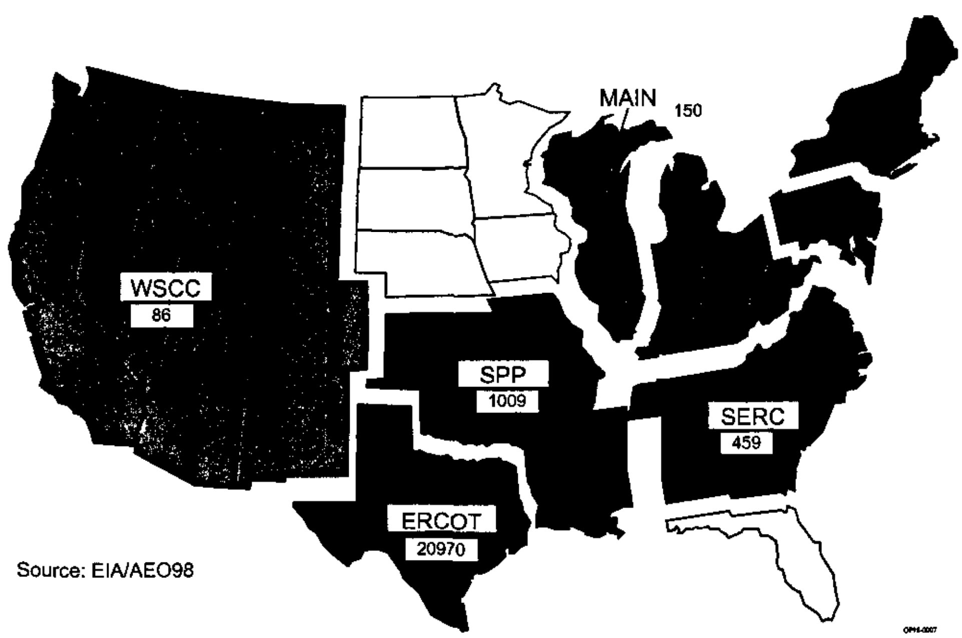


7.4.2 Replacement Capacity

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.

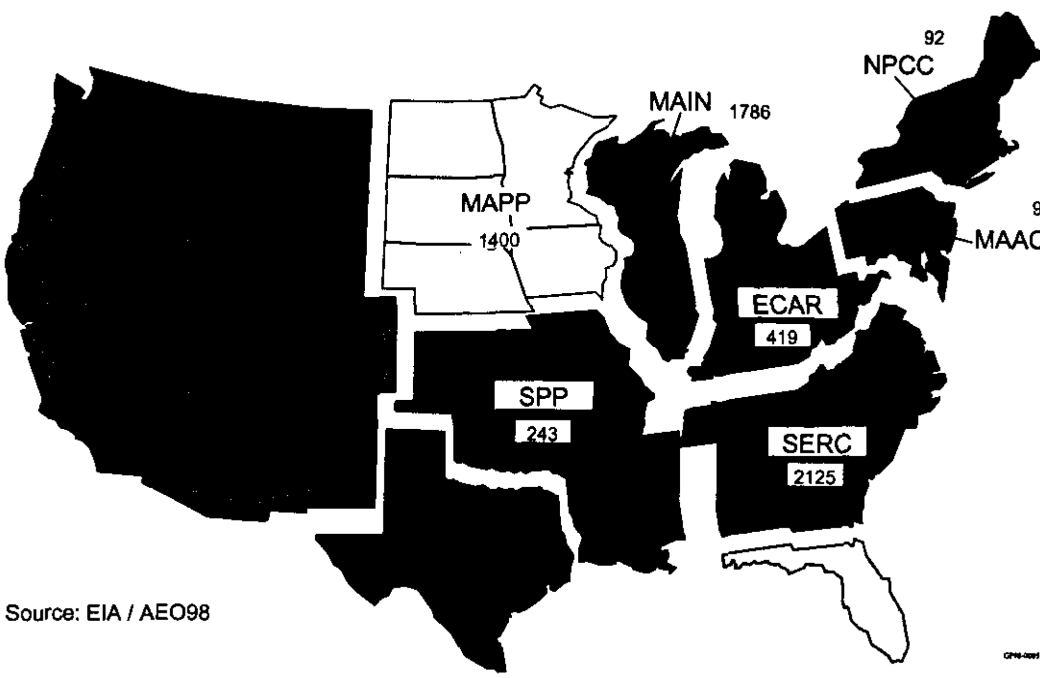
Gas: Approximately 3 GW of natural gas-fired capacity will reach an age of 50 years or older by 2020. Of this, more than 930 MW of gas-fired capacity (16 plants) will be a candidate for retirement/replacement between 2001-2005 and an additional 1,900 MW after 2005. These retirement/replacement dates 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



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)

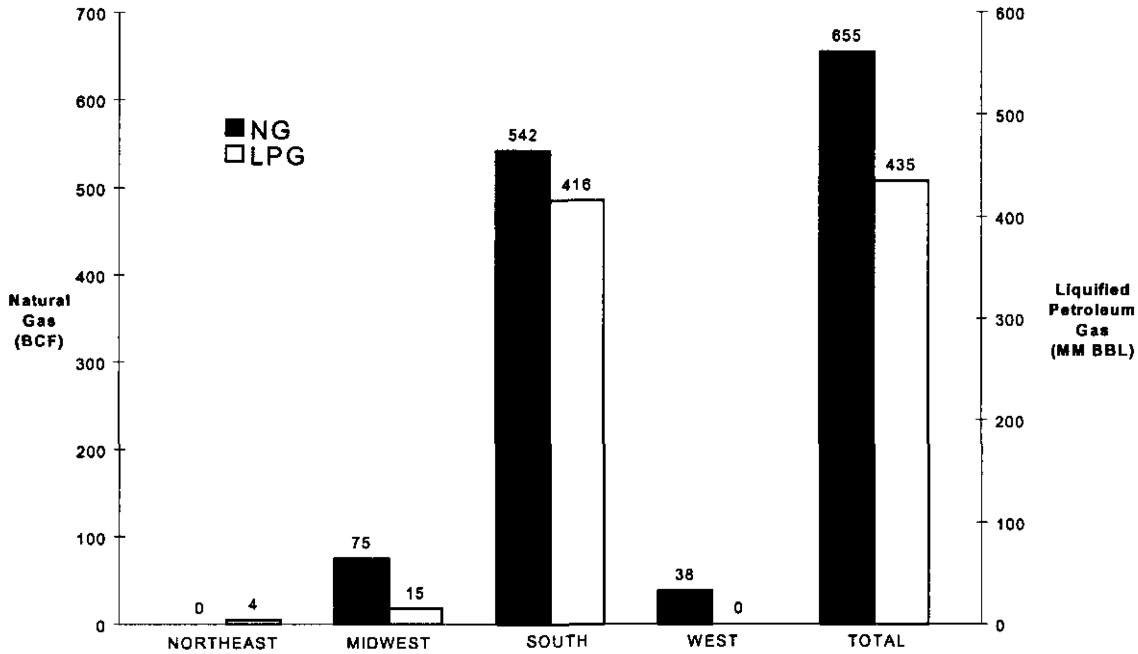
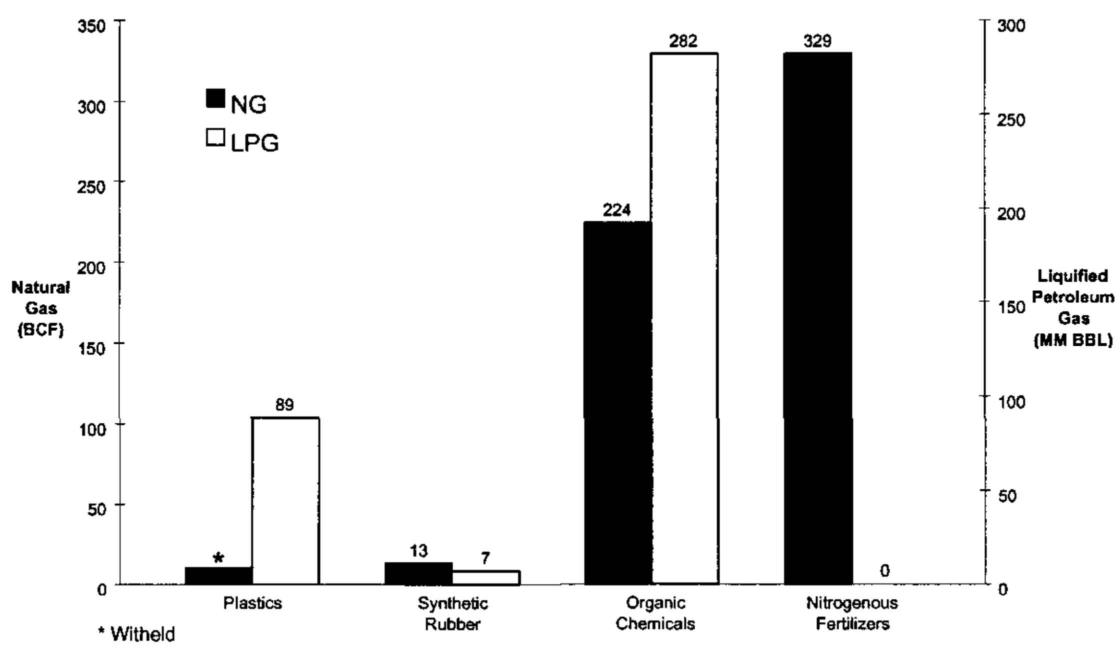


FIGURE 7-12: NATURAL GAS AND LPG USE AS FEEDSTOCK, BY MAJOR INDUSTRIAL CONSUMERS (1994)



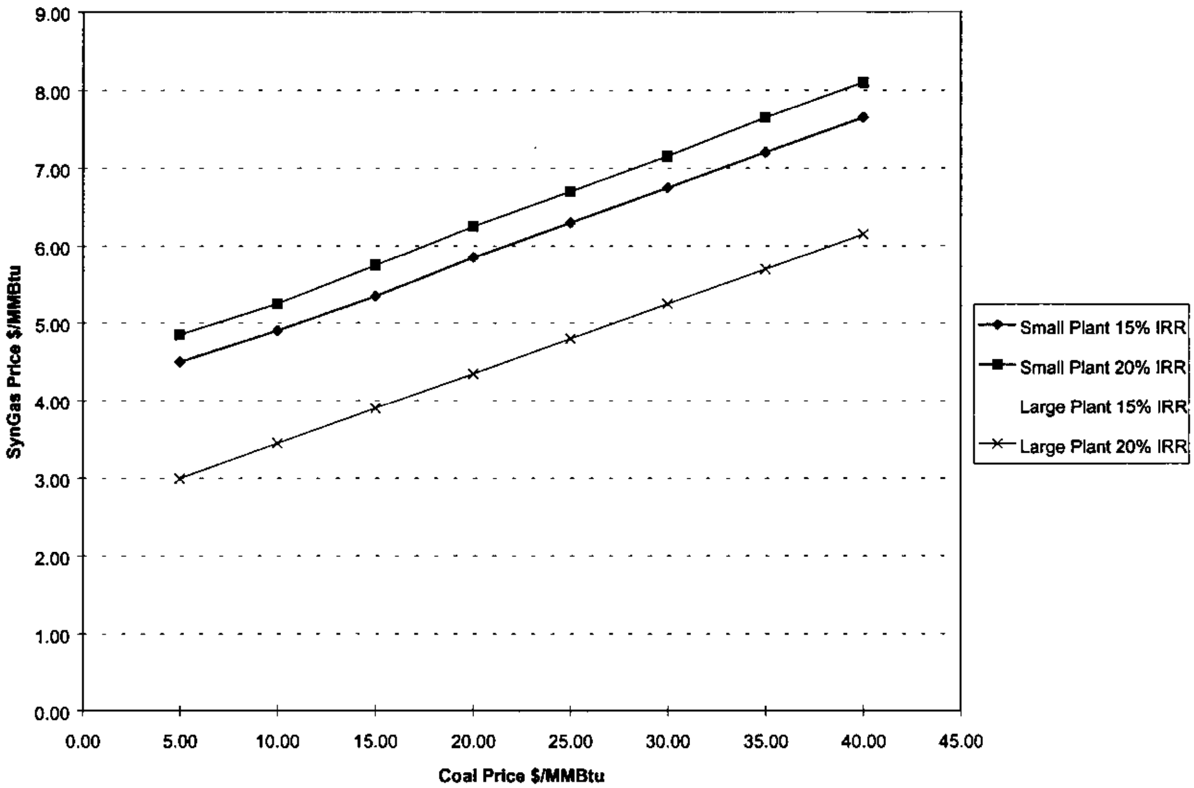
* Witheld

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