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**DEVELOPMENT OF A HIGH-PERFORMANCE
COAL-FIRED POWER GENERATING SYSTEM WITH
PYROLYSIS GAS AND CHAR-FIRED
HIGH TEMPERATURE FURNACE (HITAF)**

DE-AC22-91PC91154

**Quarterly Progress Report 12
September through December 1994**

**Prepared for
Pittsburgh Energy Technology Center
Pittsburgh, Pennsylvania**

FWDC Project 9-41-3492

June 1995

**We have no objection from a patent
standpoint to the publication or
dissemination of this material.**

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Date

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QUARTERLY PROGRESS REPORT 12 (October through December 1995)

INTRODUCTION

A concept for an advanced coal-fired combined-cycle power generating system is currently being developed. The first phase of this three-phase program consists of conducting the necessary research and development to define the system, evaluating the economic and technical feasibility of the concept, and preparing an R&D plan to develop the concept further.

Foster Wheeler Development Corporation (FWDC) is leading a team of companies involved in this effort. The team consists of:

- AlliedSignal Aerospace Company—AiResearch Division
- Bechtel Corporation
- Research-Cottrell
- TRW, Inc.
- Foster Wheeler Energy Corporation (FWEC)
- General Electric Corporation.

The power generating system being developed in this project will be an improvement over current coal-fired systems. Goals have been specified that relate to the efficiency, emissions, costs, and general operation of the system. These goals are:

- Total station efficiency of at least 47 percent.
- No more than: 0.15 lb NO_x/10⁶ Btu fuel heat input
0.15 lb SO_x/10⁶ Btu fuel heat input
0.0075 lb of particulates/10⁶ Btu fuel heat input.
- All solid wastes must be benign. Generation of solid wastes is minimized through production of usable by-products.
- Over 95 percent of the total heat input is ultimately from coal, with initial systems capable of using coal for at least 65 percent of the heat input.

- Efficient and economic baseload power generation:
 - Operation with a range of U.S. coals
 - Annual capacity factor of 65 percent
 - Load following with minimal degradation in efficiency
 - Net electrical output as low as 100 MW
 - 10-percent lower cost of electricity (COE) relative to a modern coal-fired plant conforming to NSPS.
- Safety, reliability, and maintainability to meet or exceed conventional coal-fired power plants.
- Amenable to construction using factory-assembled modular components based upon standard design.

There are two basic arrangements of our HIPPS cycle. Both are coal-fired combined cycles. One arrangement is the 35% natural gas HIPPS. A simplified process flow diagram of this system is shown in Figure 1. Coal is converted to fuel gas and char in a pyrolysis process, and these fuels are fired in separate parts of a high temperature advanced furnace (HITAF). The char-fired furnace produces flue gas that is used to heat gas turbine air up to 1400°F. Alloy tubes are used for these tube banks.

After leaving the alloy tube banks, the gas turbine air goes through a ceramic air heater where it is heated from 1400°F to 1800°F. The flue gas that goes through the ceramic air heater comes from the combustion of the fuel gas that is produced in the pyrolysis process. This fuel gas is cleaned to remove particulates and alkalies that would corrode and plug a ceramic air heater. The air leaving the ceramic air heater needs to be heated further to achieve the efficiency goal of 47%, and this is done by firing natural gas in the gas turbine combustor.

An alternative arrangement of the HIPPS cycle is called the All Coal HIPPS. With this arrangement, the char is used to heat the gas turbine air to 1400°F as before, but instead of then going to a ceramic air heater, the air goes directly to the gas turbine combustor. The fuel gas generated in the pyrolyzer is used as fuel in the gas turbine combustor. A simplified process flow diagram of this cycle arrangement is shown in Figure 2. In both cycle arrangements, heat is transferred to the steam cycle in the HITAF and a heat recovery steam generator (HRSG).

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Ref.: DE-AC22-91PC91154
Date: May 1995

Figure 1 35 Percent Natural Gas HIPPS

Date: May 1995

Task 3 - Preliminary R&D**Subtask 3.22 - Fuel Gas Burner Development**

In the 35 Percent Natural Gas HIPPS, fuel gas is fired in the HITAF upstream of the ceramic air heater. Tests were run by T-Thermal Corporation to demonstrate the operation of commercial burners with the HIPPS fuel and vitiated combustion air and to obtain emissions data from this operation. Fuel gas and vitiated combustion air were synthesized and fired in a 3 MMBtu/h burner. The test conditions were set to match the anticipated composition and temperatures of the two streams in the commercial plant. The fuel gas will be about 1100°F, and the composition will be as indicated in Table 1. The gas turbine exhaust air used for combustion will be around 870°F with a composition as listed in Table 2.

Table 1 Commercial Plant Fuel Gas Composition

Compound	wt%
CO	21.77
CO ₂	12.52
H ₂	1.18
H ₂ O	5.22
CH ₄	1.31
NH ₃	0.16
H ₂ S	0.04
O ₂	0
N ₂	57.80

Table 2 Commercial Plant Combustion Air Composition

Compound	wt%
O ₂	20.0
N ₂	75.4
H ₂ O	2.4
CO ₂	2.2

Once the usual equipment shakedown problems were resolved, there were no problems burning the fuel gas under HIPPS conditions. The flame had no observable pattern, but combustion was stable. All that was visible in the side mounted sight ports was a bright yellow glow tinted with orange, which filled the furnace and gradually became darker and more orange toward the stack end of the furnace.

There are two aspects of the HIPPS fuel gas combustion system that could impact NO_x generation. The first is the effect of the increased inlet air and fuel temperatures on thermal NO_x. The other aspect is the conversion of ammonia in the fuel gas to NO_x. Both of these phenomena were investigated in the tests. The ammonia levels in the fuel gas were varied from zero to 0.43 percent weight. The anticipated level is 0.16 percent weight under commercial plant conditions.

Even at fuel gas and vitiated air temperatures of over 900°F, the thermal NO_x was only 0.04 lb NO₂/MMBtu. This situation is a result of the use of gas turbine exhaust for combustion and the pyrolyzation process which is in effect a staged combustion. The lower oxygen content of the combustion air increases the air-to-fuel gas ratio and tends to lower the peak flame temperature. Also, the pyrolyzation process is somewhat like the substoichiometric stage in a staged, low-NO_x burner. The initial reactions of combustion are done in the pyrolyzer at relatively low temperatures and with a deficiency of oxygen. The combustion is then completed in the burner and furnace.

A high percentage of the ammonia in the fuel gas was converted to NO_x. At the ammonia levels that are predicted for the plant, about 76 percent of the ammonia nitrogen went to NO_x. This conversion rate will yield 0.8 lb NO₂/MMBtu which is far above the initial plant goal of 0.15 lb NO_x/MMBtu and the revised goal of 0.06 lb NO_x/MMBtu. There are two ways to reduce the NO_x. one way would be to design a burner specifically to minimize the conversion of the fuel bound nitrogen. The other approach is to use flue gas DeNO_x systems.

There are commercially available low-NO_x gas burners, but they are designed to minimize thermal NO_x since ammonia is not significant in natural gas. The development work done on gas turbine combustors for fuel gas indicates that it is possible to obtain

conversion rates below 30 percent with this type of fuel [1].

Figure 3 illustrates the trade-off situation between fuel gas burner NO_x generation and the application of flue gas DeNO_x systems. The upper curve in this figure illustrates the DeNO_x equipment that would be selected under the Phase 1 requirement of less than 0.15 lb NO_x /MMBtu for the entire plant. With this emissions requirement, only the HITAF flue gas stream would need treatment. If the fuel gas burner ammonia conversion is below about 24 percent, a selective noncatalytic reduction (SNCR) system could be used. Above 24 percent ammonia conversion, a selective catalytic reduction (SCR) system would be required. In each case, with a plant goal of 0.15 lb NO_x /MMBtu, no system would be required in the gas turbine exhaust stream.

The lower curve of Figure 3 illustrates the situation with a NO_x emissions goal of 0.06 lb NO_x /MMBtu which was specified in the Phase 2 RFQ. With this limit, an SCR would be required in the HITAF stream even if the fuel gas burners converted less than 19 percent of the ammonia to NO_x . Up to that conversion rate, however, only the HITAF flue gas stream would have to be treated. At higher ammonia conversion rates in the burners, SCR's would have to be applied in both the HITAF and gas turbine exhaust streams.

The preceding analysis indicates that it may be possible to lower plant costs by developing a low- NO_x fuel gas burner, but it is not certain the required ammonia conversion rate to effect these savings can be achieved. At this point, it will be assumed that backend DeNO_x systems will be used to obtain the NO_x emissions goals.

Test System

A flow schematic of the test system is shown in Figure 4. Three refractory lined furnaces were used for the tests. Two of the furnaces were fired with natural gas and were used for the production of fuel gas and the vitiated combustion air. The third furnace simulated the HITAF burner and furnace. The air furnace and its heated bypass system were adjusted to obtain the temperature and composition of the gas turbine exhaust stream that will be used for combustion air in the commercial plant. The fuel furnace was used with metered quantities of several chemical species to synthesize the fuel gas and obtain the correct temperature.

A forced draft blower provided the air required by the system, and an electric circulation heater was provided to preheat some of this air if needed. Some of the air from the heater went to the T-Thermal™ LPV-1 burner mounted on the air furnace. In the burner, natural gas was mixed with the air and burned at a high excess air rate. The products of this combustion process were then mixed with the rest of the air from the heater to produce the simulated gas turbine exhaust.

Figure 3 Effects of Ammonia Conversion on System NO_x Equipment Requirements

Figure 4 Fuel Gas Burner Test Schematic

To produce the simulated fuel gas, natural gas was mixed with a limited amount of air from the blower in a T-Thermal™ LV-1 burner mounted on the fuel furnace. The natural gas was only partially burned, since not enough air was provided for complete combustion. Nitrogen, carbon monoxide, carbon dioxide, natural gas, hydrogen, ammonia, and hydrogen sulfide were then combined, preheated in a second electric circulation heater, and mixed with the products of partial combustion to obtain a simulated fuel gas with the desired composition and temperature.

The HITAF burner was a T-Thermal™ LPV-3 vortex with a modified injector to accommodate the larger mass flow of fuel gas relative to natural gas. The burner was mounted on a refractory lined barrel shaped furnace. The photographs in Figure 5 show the three furnaces. In the bottom photograph, the furnace on the left is the HITAF furnace. The furnace in the center is the air furnace, and the one on the right is the fuel furnace. The upper photograph in Figure 5 shows the fuel furnace, the HITAF furnace and the stack. All the furnaces were refractory lined. The HITAF furnace is a 24 feet long with 30-inch I.D. It provided over 2 seconds residence time.

A schematic diagram of the emissions monitoring system is shown in Figure 6.

Figure 5 Fuel Gas Burner Test Facility

Figure 6 Instrumentation System

Data Analysis

The data from the test runs was analyzed in the following manner:

- Data from the raw data sheets were reduced to actual mass flow (lb/h) inputs into the incinerators.
- The estimated pressures and pressure drops were calculated from measured pressures, calculated velocity pressures, calculated draft, and pressure loss calculations based on Industrial Ventilation, ACGIH.
- Heat inputs were calculated from quoted fuel higher heated values and from fuel flow rates determined by rotameter indications.
- The results from the collected data were qualified by calculating oxygen and carbon balances from the following independent sources:
 - Direct orifice and rotameter mass input calculations.
 - Measured stack composition data.
- Theoretical air was calculated by dividing the oxygen required for combustion by the weight fraction of oxygen in ambient air. Excess air and percent of theoretical air were determined by comparing the measured combustion air to the theoretical air. The measured HITAF air was adjusted by dividing the oxygen in the air furnace by the weight fraction of oxygen in ambient air to express the measured HITAF air as the oxygen equivalent ambient air flow.
- Raw NO_x , SO_x , CO and HC readings, and calculated heat inputs and exhaust gas flows were used to determine the corrected NO_x and CO values.

Few significant sources of error existed in the reduced data, as reflected by small differences in the total oxygen and total carbon calculations.

In this test, the fuels were natural gas, which has an elemental composition which is relatively consistent and does not change significantly over time, and compressed gases, which are essentially pure. Therefore, any error due to fuel composition fluctuations was minimal in this test.

All input flows were monitored with a rotameter or with an orifice connected to either a slant tube manometer or U-tube manometer. All manometers were zeroed and all rotameters were calibrated prior to the test, to minimize input flow errors. The rotameter used to replace the natural gas rotameter which broke during the test was calibrated after the test. Rotameter readings were corrected for pressure and temperature, and were assumed to be linearly proportional to flow over a given range. No SO_x was detected,

even though approximately 190 ppmv of SO_x was expected for all runs except the 19:00 run, where none was expected. This could be due to a sticking H₂S rotameter float. The SO_x measurement is not an issue because it is well documented that all the sulfur will go to the SO_x in this type of combustion.

All stack analyzers were calibrated prior to the test to insure accurate stack gas concentration readings. Based on the oxygen and carbon balances, there was little error from analyzer drift or infiltration of air in the sampling system. The false high CO and HC readings on the 2 second HITAF emissions at 19:00 were probably caused by temporary contamination from pipe dope near the furnace end of the sample line which had not yet been burned out. These data were not used.

Results

The emissions results from the tests are summarized in Table 3. It can be seen that the NO_x was low when no ammonia was included in the fuel gas. As the ammonia concentration was increased the amount of NO_x increased significantly. The NO_x level versus fuel gas ammonia content is shown in Figure 7. Our analysis of the pyrolyzer operation indicates that the ammonia content of the fuel gas will be around 0.16 percent weight under the commercial plant conditions. It can be seen in Figure 7 that the rate of increase in NO_x production falls off as ammonia levels increase. This is further illustrated in Figure 8 where the percent conversion of ammonia to NO_x is plotted versus the weight percent of ammonia in the fuel gas. The conversion of ammonia to NO_x is about 76 percent at the anticipated commercial plant ammonia level.

Table 3 Summary of Emissions Results

Run Time	Ammonia Wt% of Fuel	Windbox O ₂ Dry Vol. %	Stack O ₂ Dry Vol. %	NO _x ppmvd at 3% O ₂	CO ppmvd at 3% O ₂
19:00	0	16.3	3.0	29	9
19:30	0.21	16.3	2.5	823	7
21:05	0.12	16.2	2.7	573	8
20:45	0.20	16.2	3.3	842	8
20:30	0.35	16.3	3.0	1118	9
20:05	0.43	16.3	2.6	1183	7

A complete listing of the test data is contained in Table 4. The reduced data is listed in Table 5.

Figure 7 NO_x Emissions vs. Ammonia in Fuel Gas

Figure 8 Ammonia Nitrogen Conversion vs. Ammonia in Fuel Gas

Table 4 Fuel Gas Burner Test Data

RUN TIME		1900	1930	2005	2030	2045	2105
MASS INPUTS							
Natural Gas to Air Furnace	(lbs/hr)	25.3	25.3	25.3	25.3	25.3	25.3
Comb. Air to Air Furnace	(lbs/hr)	675.8	675.8	675.8	678.2	674.9	673.7
Bypass Air	(lbs/hr)	889.7	889.7	889.7	889.9	881.4	883.5
Natural Gas to Fuel Furnace	(lbs/hr)	32.0	31.9	32.0	32.0	31.9	31.9
Comb. Air to Fuel Furnace	(lbs/hr)	247.9	237.4	231.8	237.2	236.1	230.6
Purge/Cooling Carbon Dioxide	(lbs/hr)	6.2	6.2	6.1	6.2	6.3	6.3
Nitrogen	(lbs/hr)	207.4	209.3	209.5	209.5	208.8	208.8
Carbon Monoxide	(lbs/hr)	74.0	74.9	74.1	71.7	67.1	80.2
Mix Carbon Dioxide	(lbs/hr)	63.0	66.3	63.8	66.6	67.0	68.8
Hydrogen	(lbs/hr)	5.5	5.5	6.1	6.1	6.1	5.7
Mix Natural Gas	(lbs/hr)	12.0	12.1	12.1	12.1	12.0	12.0
Ammonia	(lbs/hr)	0.0	1.4	2.7	2.2	1.3	0.8
Hydrogen Sulfide	(lbs/hr)	0.0	0.4	0.4	0.4	0.5	0.5
HITAF Pilot Natural Gas	(lbs/hr)	2.2	2.2	2.2	2.2	2.2	2.2
Purge/Cool. & HITAF Pilot Air	(lbs/hr)	54.7	54.7	54.6	54.6	54.5	54.5
Total Air Furnace Outlet	(lbs/hr)	1590.9	1590.9	1590.8	1593.4	1581.6	1582.5
Total Fuel Furnace Outlet	(lbs/hr)	648.0	645.5	638.6	644.1	637.0	645.6
TEMPERATURE PROFILE							
Air Furnace Combustion Air	(°F)	50	50	50	50	50	50
Air Furnace Burner	(°F)	1457	1466	1474	1486	1486	1491
Bypass Air	(°F)	65	65	65	65	65	65
Fuel Furnace Combustion Air	(°F)	48	48	49	49	49	50
Fuel Furnace Burner	(°F)	1223	1196	1283	1293	1311	1309
Gas Heater Outlet	(°F)	42	42	510	431	540	542
HITAF Burner Windbox Inlet	(°F)	909	915	921	924	930	927
HITAF Burner Fuel Injector	(°F)	902	886	1006	1018	1046	1043
HITAF Burner Outlet (1.5-ft.)	(°F)	2423	2495	2522	2506	2491	2542
HITAF Furnace (13.5-ft.)	(°F)	1997	2071	2111	2119	2116	2147
HITAF Furnace (23.5-ft.)	(°F)	1641	1716	1767	1792	1799	1825
Stack Temperature	(°F)	1526	1585	1630	1652	1659	1681

Table 4 Fuel Gas Burner Test Data (Continued)

RUN TIME		1900	1930	2005	2030	2045	2105
PRESSURE PROFILE							
Calc. Air Furnace Pressure	("w.c.)	6.4	7.2	7.3	7.6	7.7	8.1
Gas Heater Outlet Pressure	("w.c.)	34.0	34.0	36.0	36.0	36.0	37.0
Calc. Fuel Furnace Pressure	("w.c.)	33.8	33.8	35.7	35.7	35.7	36.7
Calc. Fuel Furnace Outlet DP	("w.c.)	6.2	6.1	6.7	6.8	6.9	6.9
Calc. HITAF Injector DP	("w.c.)	27.7	27.8	29.0	28.9	28.8	29.8
HITAF Burner Windbox DP	("w.c.)	5.7	6.5	6.6	6.9	7.0	7.4
Calc. HITAF Furnace Pressure	("w.c.)	-0.1	-0.0	-0.0	-0.0	-0.0	-0.0
AIR FURNACE OUTLET COMPOSITION							
Carbon Monoxide	(ppmvd)	180	178	187	208	175	214
Carbon Dioxide	(% Dry Vol.)	3.0	3.0	3.0	3.1	3.1	3.0
NO _x	(ppmvd)	12	16	15	15	14	14
SO _x	(ppmvd)	0	0	0	0	0	0
Oxygen	(% Dry Vol.)	16.3	16.3	16.3	16.3	16.2	16.2
HITAF EMISSIONS (1s)							
Carbon Monoxide	(ppmvd)	9	10	8	9	8	8
Carbon Dioxide	(% Dry Vol)	12.8	12.7	12.8	12.4	12.3	12.9
NO _x	(ppmvd)	30	860	1210	1120	825	587
SO _x	(ppmvd)	0	0	0	0	0	0
Oxygen	(% Dry Vol.)	3.0	2.7	2.6	3.0	3.2	2.7
Hydrocarbons	(ppmv)	12.4	15.0	11.5	12.6	12.9	13.6
Actual Residence Time	(s)	1.5	1.5	1.4	1.4	1.5	1.4

Table 4 Fuel Gas Burner Test Data (Continued)

RUN TIME		1900	1930	2005	2030	2045	2105
HITAF EMISSIONS (2s)							
Carbon Monoxide	(ppmvd)	345	5	7	8	8	9
Carbon Dioxide	(% Dry Vol)	12.4	13.2	13.1	12.6	12.3	13.0
NO _x	(ppmvd)	27	834	1215	1120	835	575
SO _x	(ppmvd)	0	0	0	0	0	0
Oxygen	(% Dry Vol.)	3.0	2.3	2.5	2.9	3.3	2.8
Hydrocarbons	(ppmv)	79.0	12.2	12.8	13.5	13.3	13.4
Actual Residence Time	(s)	2.8	2.7	2.7	2.7	2.7	2.7

Table 5 Fuel Gas Burner Reduced Data

CALCULATED DATA

FUEL HEAT INPUTS

Nat. Gas to Air Furn. Burner	(MM Btu/hr)	0.58	0.58	0.58	0.58	0.58	0.58
Nat. Gas to Fuel Furn. Burner	(MM Btu/hr)	0.74	0.74	0.74	0.74	0.74	0.74
Carbon Monoxide	(MM Btu/hr)	0.32	0.33	0.32	0.31	0.29	0.35
Hydrogen	(MM Btu/hr)	0.34	0.34	0.37	0.37	0.37	0.35
Mix Natural Gas	(MM Btu/hr)	0.28	0.28	0.28	0.28	0.28	0.28
Ammonia	(MM Btu/hr)	0.00	0.01	0.01	0.01	0.01	0.00
Hydrogen Sulfide	(MM Btu/hr)	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas to HITAF Pilot	(MM Btu/hr)	0.05	0.05	0.05	0.05	0.05	0.05
Total Fuel Heat Input	(MM Btu/hr)	2.31	2.32	2.37	2.35	2.35	2.35

OXYGEN BALANCE

Total to Air Furn. by Inputs	(lbs/hr)	365	365	365	366	363	363
Total to Air Furn. by Stack	(lbs/hr)	376	375	376	378	373	372
Difference	(%)	2.9	2.7	3.1	3.4	2.9	2.6
Total to HITAF by Inputs	(lbs/hr)	529	529	526	528	523	530
Total to HITAF by Stacks	(lbs/hr)	530	527	534	534	531	530
Difference	(%)	0.2	-0.4	1.6	1.2	1.7	0.0

CARBON BALANCE

Total to Air Furn. by Inputs	(lbs/hr)	19	19	19	19	19	19
Total to Air Furn. by Stack	(lbs/hr)	19	19	19	20	19	19
Difference	(%)	2.5	0.8	3.5	7.5	3.7	2.2
Total to HITAF by Inputs	(lbs/hr)	103	105	104	103	101	108
Total to HITAF by Stack	(lbs/hr)	105	107	107	104	101	107
Difference	(%)	1.7	2.6	2.9	0.1	-0.2	-0.8

Table 5 Fuel Gas Burner Reduced Data (Continued)

CALCULATED DATA

STOICHIOMETRY

Theor. Air Furnace Comb. Air (lbs/hr)	426	426	426	426	425	425
Meas. Air Furnace Comb. Air (lbs/hr)	676	676	676	678	675	674
Air Furnace Excess Air (%)	58.5	58.5	58.5	59.1	58.8	58.5
Theor. Fuel Furn. Comb. Air (lbs/hr)	535	534	534	534	533	532
Meas. Fuel Furn. Comb. Air (lbs/hr)	248	237	232	237	236	231
Fuel Furn. Air a % of Theor. (%)	46.4	44.5	43.4	44.4	44.3	43.3
Theoretical HITAF Comb. Air (lbs/hr)	901	923	957	943	923	943
Measured HITAF Comb. Air (lbs/hr)	1201	1201	1201	1204	1192	1193
HITAF Excess Air (%)	33.3	30.1	25.4	27.6	29.2	26.6

HITAF AIR COMPOSITION

Oxygen (Wt. %)	16.6	16.6	16.6	16.7	16.6	16.6
Nitrogen (Wt. %)	75.5	75.5	75.5	75.5	75.5	75.5
Water (Wt. %)	3.6	3.6	3.6	3.6	3.6	3.6
Carbon Dioxide (Wt. %)	4.3	4.3	4.3	4.3	4.3	4.3

HITAF FUEL COMPOSITION

Carbon Monoxide (Wt. %)	17.6	18.0	18.4	17.9	17.2	19.2
Carbon Dioxide (Wt. %)	14.2	14.5	13.8	14.1	14.5	14.4
Hydrogen (Wt. %)	1.7	1.7	1.8	1.8	1.8	1.7
Water (Wt. %)	3.3	3.0	2.9	3.2	3.1	2.9
Methane (Wt. %)	1.9	1.9	1.9	1.9	1.9	1.9
Ammonia (Wt. %)	0.0	0.2	0.4	0.3	0.2	0.1
Hydrogen Sulfide (Wt. %)	0.0	0.1	0.1	0.1	0.1	0.1
Oxygen (Wt. %)	0.0	0.0	0.0	0.0	0.0	0.0
Nitrogen (Wt. %)	61.4	60.6	60.6	60.8	61.2	59.8

Table 5 Fuel Gas Burner Reduced Data (Continued)

RUN TIME		1900	1930	2005	2030	2045	2105
EXHAUST GAS FLOW							
Theoretical Flow Temp.	(°F)	2763	2796	2889	2864	2856	2902
Stack Flow Rate (WET)	(mol/hr)	80.83	80.72	80.71	80.98	80.33	80.30
	SCFH	31265	31224	31220	31323	31073	31062
Stack Flow Rate (DRY)	(mol/hr)	69.33	69.12	68.67	68.98	68.48	68.72
	DSCFH	26819	26735	26563	26682	26489	26580
EMISSION LEVELS							
Stack Oxygen	%[dry]	3.0	2.5	2.6	3.0	3.3	2.7
NO _x	(ppmvd)	28.5	847.0	1212.5	1120.0	830.0	581.0
NO _x at 3% O ₂	(ppmvd)	28.5	822.9	1183.2	1117.8	841.7	572.7
NO _x as NO ₂	(lbs/hr)	0.0909	2.6933	3.8307	3.5543	2.6150	1.8368
	lb/MMBtu	0.0393	1.1592	1.6189	1.5102	1.1262	0.7817
SO _x	(ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0
SO _x at 3% O ₂	(ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0
Carbon Monoxide	(ppmvd)	9.0	7.5	7.5	8.5	8.0	8.5
CO at 3% O ₂	(ppmvd)	9.0	7.3	7.3	8.5	8.1	8.4
Hydrocarbons	(ppmvd)	12.4	13.6	12.2	13.1	13.1	13.5
Hydrocarbons at 3% O ₂	(ppmvd)	12.4	13.2	11.9	13.0	13.3	13.3

As previously discussed, it is likely that improvements could be made in burner design to reduce the conversion of fuel bound nitrogen. However, when the NO_x situation is analyzed based on the entire system, it is not certain that burner development is warranted. Given the overall NO_x goals, ammonia conversion levels down around 20 percent would be required to materially affect emissions system costs. At this time, burner development is not planned although this decision will be reevaluated as more information is obtained on other parts of the system.

The tests showed that combustion of the low-Btu fuel gas with vitiated air is not a problem. Flame stability and fuel burnout can be accomplished with simple commercially available burners.

The fuel gas burner results pertain only to the 35 Percent Natural Gas HIPPS. In the All Coal HIPPS, the fuel gas will only be fired in the gas turbine. The base case design will use the Westinghouse MASB combustor which has been shown to have ammonia

conversion rates of only 20-30 percent.

4.22 Commercial Acceptance of HIPPS

It is believed that repowering applications of HIPPS will provide a means of gaining early market acceptance of the technology. A repowering arrangement of our HIPPS plant is being developed to evaluate the technical and economic aspects of the system. Delmarva Power is helping us do a study of repowering for their Indian River Plant. It is planned to repower Units #1 and #2 starting with Unit #2 in 1999. They are currently considering repowering with atmospheric fluidized bed boilers.

The FWDC HIPPS lends itself to a repowering arrangement that has some unique features. We believe that it will fill a market niche that is not adequately covered with available repowering technologies. The HIPPS repowering will increase both system capacity and efficiency while making maximum use of existing plant equipment. It will also not require the switching of plant fuel from coal to natural gas.

A block diagram of the HIPPS repowering arrangement is shown in Figure 9. The existing boiler is reused, but it is fired with a mixture of coal and char from the HIPPS pyrolyzer. Fuel gas from the pyrolyzer is fired in a gas turbine, and the exhaust from the gas turbine is used as combustion air in the boiler. This system is similar in concept to "hot windbox" repowering which has been applied in Europe and Japan. An important difference is that HIPPS repowering is a coal-fueled system for use on a coal-fired boiler.

The Indian River units are 1950's vintage Babcock and Wilcox units. They are PC-fired with bituminous coal. operating parameters for each of the units are listed in Table 6. HIPPS repowering design and cost estimates are being done both on the basis of reusing the existing boiler and on the basis of replacing the boiler. The main market niche for HIPPS repowering will probably be applications where the existing boiler life can be extended. In this particular situation, the customer may want to replace the boiler.

Table 6 Indian River Unit No. 1 and Unit No. 2 Operating Parameters

Net Load (MW)	93.7
Main Steam Flow (lb/h)	665,430
Reheat Steam Flow (lb/h)	589,750
Main Steam Conditions (PSIG/°F)	1815/1005
Reheat Steam Conditions (PSIG/°F)	432/991
Firing Rate (MBTU/h)	953.9
Heat Rate (BTU/kw-h)	10,168

Figure 9 Block Diagram of HIPPS Repowering

A preliminary performance analysis and heat and material balance were done for HIPPS repowering of the Indian River boilers. The cycle arrangement was kept as simple as possible with a high priority given to reliability and flexibility of operation. The cycle analysis is preliminary because we are still evaluating some design options and the performance of individual system components. However, it appears that the repowering will increase system capacity by about 20 percent and increase cycle efficiency by about 5 percentage points.

A process flow Schematic of the repowered boiler is shown in Figure 10. The cycle is based on a Westinghouse 251 gas turbine with one row of compressor blades eliminated. With HIPPS repowering, the optimum gas turbine size is determined by the size of the existing steam cycle. It is desirable to size the gas turbine such that all the exhaust gas can be used as combustion air for the boiler. When the gas turbine is sized in this manner, there is only one flue gas exhaust stream from the unit. For the Indian River conditions, a straight 251 gas turbine would be a little too large. The modified 251 gas turbine can currently be supplied.

The pyrolyzer in the repowering HIPPS arrangement will be a jetting fluidized bed. Because the fuel flow to the boiler will be approximately a 50/50 split of coal and char, the simplest approach will be to pulverize the coal and char together in a typical direct-fired mill-burner arrangement. A jetting fluidized bed pyrolyzer with relatively coarse feed (approximately 1/8-in. x 0-in.) will suit this application well. Char will be removed from the bed and from downstream particulate removal equipment. A preliminary sketch of the pyrolyzer subsystem is shown in Figure 11.

The fuel gas from the pyrolyzer will be cooled to around 1000°F by the injection of water. This process will condense out alkalies that could cause gas turbine problems. After being cooled, the fuel gas goes through a filter to remove particulates and the condensed alkalies. The fuel gas is then fired in the gas turbine.

The char from the pyrolyzer will be depressurized and cooled. This can be accomplished in different ways. At this point, a restrictive pipe discharge (RPD) system and bulk solids coolers appear to be the best method. The RPD system reduces pressure by taking a pressure drop across a moving bed of solids as the solids are removed from the system. This is accomplished by having a reservoir of solids above and below a standpipe. At the lower reservoir, process gas is bled off to maintain the vessel at the lower pressure.

The amount of process gas that needs to be bled off to maintain this pressure can be made to be quite low. It will be the amount of gas that is required to achieve the differential pressure as a pressure drop across a fixed bed of solids. A solids feed device at the outlet of the bottom reservoir controls the solids flow and maintains a head of solids in the standpipe. It is planned to test this type of system under HIPPS conditions in Phase 2. An alternative depressurization system would be lock hoppers.

Figure 10 Repowered HPPS Process Schematic

Figure 11 Pyrolyzer Subsystem

Cooling of the char can be accomplished with either bulk solids coolers or screw coolers. Both of these devices are commercial, and they will transfer the heat to the low pressure economizer system. Bulk solids coolers use closely spaced rectangular plate cooling elements. As the solids pass between these plates, heat is transferred to the water. It may be possible to use the cooler as the lower solids reservoir thereby reducing the number of vessels required for the system. A screw feeder or other solids feeding device will be used at the cooler outlet to control the flow of solids.

If screw coolers are used, the cooling and feeding will be accomplished in the same device. A vessel upstream of the screw cooler will be used for the lower reservoir of the RPD system. With either the bulk cooler system or the screw cooler system, the outlet of the cooling system will be designed so that the char is evenly cooled to around 200°F.

Each pulverizer will be fed coal and char from separate gravimetric feeders. To physically fit in the equipment, the feeders may feed into a constant speed screw or belt that will transport the coal and char to one inlet on each pulverizer. The pulverizers may be swept with flue gas instead of primary air. Drying requirements in the pulverizers will be greatly reduced since the char will be dry already. The use of flue gas in the pulverizers will reduce the chance of fires in this equipment.

As part of a repowering project the burners would be replaced. Either low-NO_x burners would be used in the same locations as the existing burners, or TRW slagging combustors would be added to the furnace. The technical and economic aspects of these two approaches need to be evaluated further. In any repowering application, the boiler will need to be analyzed to determine if any modifications will need to be made. It may be necessary to add some refractory in the furnace to reduce the heat absorbed there.

Since the hot gas turbine exhaust air is used for combustion, there is no need for the existing air heater. As in "hot windbox" arrangements, additional economizer surface is added in place of the air heater. Feedwater heaters are taken out of service to compensate for the additional economizer duty.

Although there are changes that need to be made to the boiler system, these changes need to be kept in perspective. Alternative repowering schemes require a complete replacement of all boiler systems. Depending on the condition of the existing equipment, HIPPS repowering could reuse the boiler, boiler fuel preparation equipment, instrumentation and controls. As previously mentioned, the Indian River study is being done both on the basis of reusing the old boiler and replacing the boiler.

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1. Domeracki, W.F. et. al., "Topping Combustor Development For Second-Generation Pressurized Fluidized Bed Combined Cycles", ASME 94-GT-176