FINAL

Engineering Development of Coal-Fired High Performance Power Systems Phase II and III

DE-AC22-95PC95144

Quarterly Progress Report

October 1 - December 31, 1998

Prepared for

Federal Energy Technology Center
Pittsburgh, Pennsylvania

United Technologies Research Center
411 Silver Lane, East Hartford, Connecticut 06108

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Abstract

This report presents work carried out under contract DE-AC22-95PC95144 "Engineering Development of Coal-Fired High Performance Systems Phase II and III." The goals of the program are to develop a coal-fired high performance power generation system (HIPPS) that is capable of:

- ◊ thermal efficiency (HHV) ≥ 47%
- ◊ NOx, SOx, and particulates ≤ 10% NSPS
(New Source Performance Standard)
- ◊ coal providing ≥ 65% of heat input
- ◊ all solid wastes benign
- ◊ cost of electricity ≤ 90% of present plants

Phase I, which began in 1992, focused on the analysis of various configurations of indirectly fired cycles and on technical assessments of alternative plant subsystems and components, including performance requirements, developmental status, design options, complexity and reliability, and capital and operating costs. Phase I also included preliminary R&D and the preparation of designs for HIPPS commercial plants approximately 300 MWe in size. This phase, Phase II, involves the development and testing of plant subsystems, refinement and updating of the HIPPS commercial plant design, and the site selection and engineering design of a HIPPS prototype plant.

Work reported herein is from:

- ◊ Task 2.1 HITAC Combustors;
- ◊ Task 2.2 HITAF Air Heaters;
- ◊ Task 6 HIPPS Commercial Plant Design Update

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Executive Summary

This report represents work carried out under contract DE-AC22-95PC95144 "Engineering Development of Coal-Fired High Performance Systems Phase II and III." The goals of the program are to develop a coal-fired high performance power generation system (HIPPS) that is capable of:

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- ◊ all solid wastes benign
- ◊ cost of electricity ≤ 90% of present plant

Work reported in this report is from Task 2.1 HITAF Combustor , Task 2.2 HITAF Air Heaters, and Task 6 HIPPS Commercial Plant Design Update.

Task 2.1 HITAF Combustors

Work during the quarter concentrated on additional development of the capability to model the application of SNCR in coal-fired boilers. Recent studies had indicated that the modified reduced mechanism was under-predicting (compared to the detailed mechanism) the NOx reduction over the range of temperatures in large (600 MWe) coal-fired utility boilers. Consequently, improved rates parameters were developed that produced a revised reduced mechanism that provides good agreement between the detailed mechanism and the reduced mechanism.

Task 2.2 HITAF Air Heaters

The pilot-scale SFS was fired on natural gas during the period December 7–11. The purpose of the December test period was to cure new refractory in the slagging furnace, slag tap, slag screen, and dilution quench zone. Initial data evaluation has been completed. The following summarizes available results and observations about each of the components for the December test period as well as SFS maintenance and modification activities.

- The high-density refractory liner in the SFS was replaced this past quarter. The inner refractory layer had undergone corrosion above the RAH panels and around the furnace exit; there was cracking and some spalling of the furnace refractory in several location; and the furnace opening previously used for the SRAH needed to be sealed since it was no longer being used.
- The slagging furnace heating rate during the December test period was limited to 50°F/hr (28°C/hr) while natural gas was fired. Hold points occurred at 250°F (121°C) for 24 hours, 650°F (344°C) for 12 hours, and nominally 3100°F (1705°C) for 2 hours. The slow heating rate was necessary to cure the new refractory in the furnace, slag tap, slag screen, and dilution/quench zone.

- When the furnace flue gas temperature near the refractory walls reached nominally 3100°F (1705°C), the main burner natural gas-firing rate was maintained at 3.0 MMBtu/hr (3.1 × 10^6 kJ/hr) for about 5.5 hr with support from an auxiliary burner firing rate of 0.5 to 0.65 MMBtu/hr (0.6 to 0.75 × 10^6 kJ/hr). Subsequently, the main and auxiliary burner natural gas-firing rates were decreased gradually to control the furnace and slag screen cooling rate to100°F/hr (56°C/hr) or less.
- Inspection of the furnace refractory after the December test indicated that the new refractory was in good condition.
- The main and auxiliary burners performed well during the December test. At this time, the EERC suggests that the slagging furnace be operated using minimum-to-moderate main burner swirl as necessary for a stable flame in order to establish uniform temperatures over the length of the furnace and to minimize NO_x emissions.
- Slag screen flue gas temperatures during the December test period reached a maximum of 2790°F (1532°C) at the inlet and 2725°F (1496°C) at the outlet, respectively. Slag screen operating temperature is selected based on ash fusion data for the fuel to be fired. The high-density refractory was in good condition at the inlet. However, refractory had spalled off the side walls of the back half of the slag screen. . The slag screen tubes will likely always require periodic replacement based on some level of erosion/corrosion and the fuels selected for testing.
- During the December test, the dilution/quench zone was effectively used to control the temperature of the flue gas entering the CAH tube bank.
- Flue gas flow was diverted through the baghouse and then bypassed through the cyclone in order to evaluate the performance of a new controller on the baghouse outlet valve. The tests indicated that it should be possible to minimize furnace pressure swings in the future when diverting flue gas flow through the baghouse or cyclone.
- While natural gas was fired and the tubes were clean, heat recovery from the CAH tube bank reached a maximum of nominally 50,000 Btu/hr (52,750 kJ/hr). The cooling-air flow rate was 150 scfm (4.2 m^3/min). The inlet cooling air was 1100°F (594°C), outlet cooling air was nominally 1400°F (760°C), and flue gas was 1850°F (1010°C) entering the CAH tube bank.
- Testing of the LRAH panel did not occur this past quarter. Reassembly of the LRAH panel is expected to occur in mid-January. The next coal-fired test to evaluate the LRAH panel is scheduled for the last week of January 1999.

Refractory tiles were removed from the LRAH and SRAH after various runs in the EERC slagging furnace. Sections of these tiles were sent to URTC for examination and evaluation. Tests being performed include flexural, metallography, and electon microprobe. Examination of tile taken from both the LRAH and SRAH indicated that the material remote from the slag region was stronger than the material nearer the slag zone, but not as strong as the as-received material. The surface of the Monofrax M tiles taken from the SRAH was discolored to a depth of up to 6 mm (¼") due to reactions with the slag. The surface of a tile of Monofrax L taken from the SRAH shows a slag reaction zone only 0.6 mm ($\frac{1}{16}$") deep.

Laboratory experiments were initiated to find a suitable coating to reduce slag penetration into the refractory. To date, eighteen different materials and combinations of materials have been tested as coatings. None of the coatings tested so far completely seal the pores, although several have reduced slag penetration in static tests by up to 35%.

In an effort to understand the variations in the permanent shrinkage measurements for the Plicast materials, dilatometer tests were performed this quarter. Dilatometer measurements to 1600°C (2910°F) were made on Plicast 98 and Plicast 96 refractory materials with and without organic fibers and Plicast 99 without fibers. Tests with the larger blocks showed that Plicast 99 without fibers had an average permanent shrinkage of 1.24%. Plicast 98 without fibers had an average permanent shrinkage of 1.32% and 0.98% with fibers. Plicast 96 without fibers had an average permanent shrinkage of 0.49% and 0.0% with fibers; however, the shrinkage up to 1200°C was similar to that for the other Plicast materials. Above that temperature, growth occurred, possibly due to the formation of a mullite phase.

Based on the few sets of data available about the shrinkage that may occur in Plicast over hundreds of hours, it appears that the greatest amount of shrinkage occurs within the first several hours at high temperature, then continues much more slowly, around 1/50th of the initial rate, over longer periods.

There is an indication that an increase of 100°C in the firing temperature can make a significant difference in the strength and, therefore, the erosion resistance of the refractory material.

Two dynamic corrosion tests were completed this quarter using the lignite slags from the SFS lignite tests. The first, which was begun last quarter, was a 100-hour dynamic slag corrosion test at 2732°F (1500°C) on blocks of fused-cast Monofrax L and Monofrax M using the Coal Creek lignite slag. After 100 hours of slag feed, the average measured recession was 0.23 inches and 0.31 inches for Monofrax L and M, respectively.

Task 6 HIPPS Commercial Plant Design Update

A HIPPS market study was performed. The study examined the current state of electric power generation in the United States, and forecasted future changes to the industry. HIPPS is shown as being competitive with other power generation technologies, including gas turbine combined cycle power plants.

Market size:

- 403,000 megawatts of capacity will be required by 2020 in the U. S. to replace older units and provide for growth. Of that total new capacity, 49,000 megawatts of the new capacity is forecast as coal-fired.
- The market for HIPPS could range from 8,000 megawatts (20% of the planned coal-fired additions) to 80,000 megawatts (about 20% of the total capacity addition).
- The megawatt range above equates to a cost range of from about $6 to $60 billion (in 1997 dollars) over the period from now to 2020.

Market timing:

- Because of the planned retirements of existing units, more than half of the added capacity will occur in the 2010 to 2020 period.
- Repowering Market:
- There are several thousand megawatts of opportunity for HIPPS in the near term (now to 2006) as utilities plan to change the capacity of existing units.

Location:

- In the U. S., the States of Ohio, Indiana, Pennsylvania, Illinois, Missouri, Tennessee and Wisconsin have the best conditions for HIPPS to enter the power generation market.
- Competitive Standing:
- The cost of electricity for HIPPS is competitive with the average prices paid for electricity in the seventeen States selected as the focus of the study.

Introduction

The High Performance Power Systems (HIPPS) electric power generation plant integrates a combustion gas turbine and heat recovery steam generator (HRSG) combined cycle arrangement with an advanced coal-fired boiler. The unique feature of the HIPPS plant is the partial heating of gas turbine (GT) compressor outlet air using energy released by firing coal in the high temperature advanced furnace (HITAF). The compressed air is additionally heated prior to entering the GT expander section by burning natural gas. Thermal energy in the gas turbine exhaust and in the HITAF flue gas are used in a steam cycle to maximize electric power production. The HIPPS plant arrangement is thus a combination of existing technologies (gas turbine, heat recovery boilers, conventional steam cycle) and new technologies (the HITAF design including the air heaters, and especially the heater located in the radiant section).

The HITAF provides heat to the compressor outlet air using two air heaters, a convective air heater (CAH), and a radiant air heater (RAH). The HITAF is a slagging furnace which contains the radiant air heater, as well as waterwalls and steam drum for the high pressure (HP) steam system. Hot flue gas leaving the HITAF furnace passes over the CAH prior to entering a heat recovery steam generator (HRSG). Hot exhaust gas from the gas turbine is ducted to another HRSG in a typical combined cycle arrangement. The HITAF, gas turbine and HRSGs are configured to achieve the required high efficiency of the HIPPS plant.

The key to the success of the concept is the development of integrated combustor/air heater that will fire a wide range of US coals with minimal natural gas and with the reliability of current coal-fired plants. The compatibility of the slagging combustor with the high temperature radiant air heater is the critical challenge.

Task 2.1 HITAF Combustors

Selective noncatalytic reduction (SNCR) is effective over a very narrow temperature range, usually considered to be approximately 850-1100^{o}C (1560-2017^{o}F). Nitric oxide (NO) removal at higher temperatures is poor because the reducing agent itself oxidizes to NO. Below the optimum temperature, the selective reduction reactions are too slow, and unreacted reagent can be emitted. An effective model of the SNCR chemistry must accurately represent this behavior over the entire temperature range existing in the furnace.

In previous work (Brouwer , *et al*., 1996), REI developed a reduced seven step mechanism describing SNCR chemistry for typical reagents (NH_3 (ammonia), NH_2CONH_2 (urea), and $(HNCO)_3$ (cyanuric acid)). This original reduced mechanism was modified by REI to improve agreement with a detailed chemical mechanism for typical flue gas conditions in a coal-fired utility boiler using SNCR with NH_3. The modified mechanism is reproduced in Exhibit 2.1-1 below and was previously incorporated into REI's three-dimensional turbulent reacting flow codes BANFF and GLACIER to model industrial boilers.

Exhibit 2.1-1
Rate Parameters for the Reduced SNCR Model

Reaction	A	b	E_a
1a. $NH_3 + NO \rightarrow N_2 + H_2O + H$ ($T < 1900^{o}F$)	1.12	5.3	37,450
1b. $NH_3 + NO \rightarrow N_2 + H_2O + H$ ($T > 1900^{o}F$)	1.68E-05	5.3	8,552
2a. $NH_3 + O_2 \rightarrow NO + H_2O + H$ ($T < 1900^{o}F$)	1.90E-01	7.65	95,253
2b. $NH_3 + O_2 \rightarrow NO + H_2O + H$ ($T > 1900^{o}F$)	5.97E-11	7.65	37,120
3. $HNCO + M \rightarrow H + NCO + M$	2.40E+14	0.85	68,000
4. $NCO + NO \rightarrow N_2O + CO$	1.00E+13	0.00	-390
5. $NCO + OH \rightarrow NO + CO + H$	1.00E+13	0.00	0
6. $N_2O + OH \rightarrow N_2 + O_2 + H$	2.00E+12	0.00	10,000
7. $N_2O + M \rightarrow N_2 + O + M$	6.90E+23	-2.50	64,760

Units are A=cm-mol-s-K; E_a = cal/mol

For an initial NOx concentration, in the flue gas, of 300 ppm, the prediction of NOx reduction and NH_3 slip using the modified reduced mechanism (Exhibit 2.1-1) was quite good in comparison with the detailed chemical mechanism. However, in recent studies, the model was applied to a large (600 MWe) coal-fired utility boiler with an initial NOx concentration of approximately 100 ppm. Comparisons of calculations using SENKIN (Key, et al., 1989) with a detailed mechanism, and calculations using BANFF with the reduced mechanism shown in Exhibit 2.1-1 indicated that the reduced mechanism was under-predicting the NOx reduction over the range of temperatures existing in the boiler.

Exhibit 2.1-2 and -3 show the comparison of results of isothermal SENKIN plug flow reactor (PFR) simulations and isothermal BANFF plug flow reactor (PFR) simulations for a residence time of 150 msec. The comparisons cover a range of temperatures and assume a typical flue gas composition as given in Exhibit 2.1-4. These exhibits show that the reduced mechanism significantly under-predicts the NOx reduction at temperatures greater than 1750 ^{o}F and 1900^{o}F using NH_3, and urea, respectively although the NH3 slip predicted using reduced mechanism is in reasonable agreement with the values predicted using detailed mechanism.

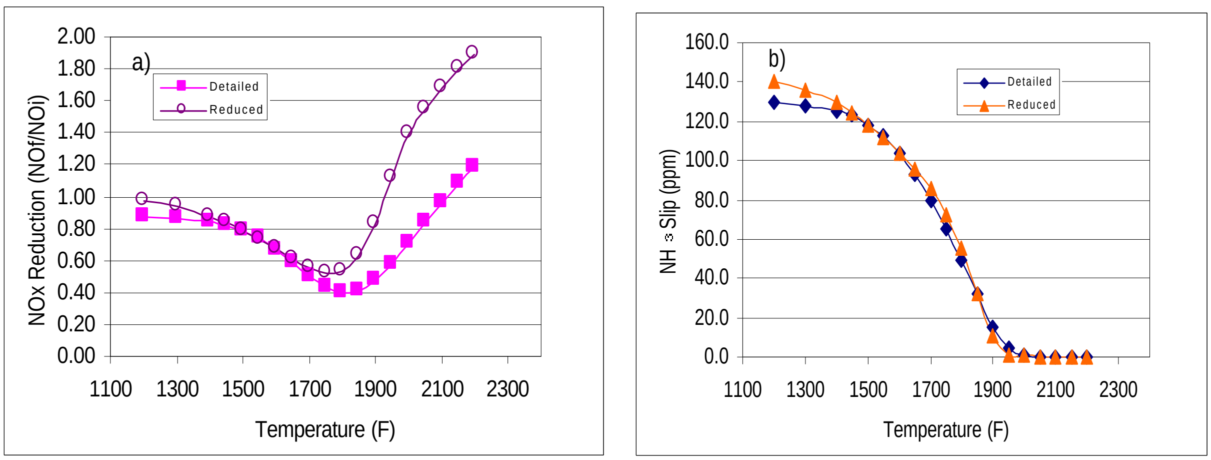


Exhibit 2.1-2
Comparison between reduced and detailed mechanisms for NH_3 at NSR=1.2
a) NOx Reduction; b) NH_3 Slip

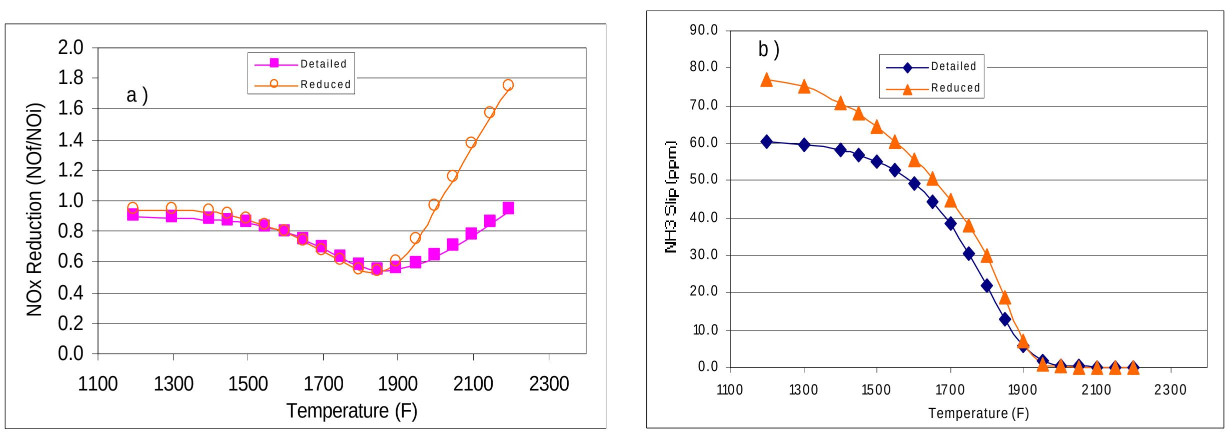


Exhibit 2.1-3
Comparison between reduced and detailed mechanisms for urea at NSR=1.2
a) NOx Reduction; b) NH_3 Slip

Exhibit 2.1-4
Typical Flue Gas Composition from Coal-Fired Boiler

NH3 as a reagent		Urea as a reagent	
Chemical Species	Mole %	Chemical Species	Mole %
N2	70.48	N2	70.48
O2	2.89	O2	2.89
CO2	14.19	CO2	14.19
H2O	12.43	H2O	12.43
OH	1.0E-03	OH	1.0E-03
O	1.0E-04	O	1.0E-04
NO	1.2E-02	NO	1.2E-02
NH3	1.44E-02	NH3	7.2E-03
HNCO	0.0	HNCO	7.2E-03

To improve upon these predictions, a series of SENKIN calculations, using the detailed mechanism, was carried out to obtain improved values, through curve fitting, for the values of A, b, and E_a, for each reaction step shown in Exhibit 2.1-1. The detailed procedure used to obtain the improved rates was outlined previously. The revised reduced mechanism is given in Exhibit 2.1-5. The same global steps were retained except for step 5 in which O_2 was used as the oxidizer instead of OH.

Exhibit 2.1-5
Rate Parameters for the Revised Reduced SNCR Model

Reaction	A	b	E_a
1a. $NH_3 + NO \rightarrow N_2 + H_2O + H$ ($T < 1900^oF$)	1.12	5.3	38246
1b. $NH_3 + NO \rightarrow N_2 + H_2O + H$ ($T > 1900^oF$)	2.99	5.3	40746
2a. $NH_3 + O_2 \rightarrow NO + H_2O + H$ ($T < 1900^oF$)	1.90E-01	7.65	95,253
2b. $NH_3 + O_2 \rightarrow NO + H_2O + H$ ($T > 1900^oF$)	1.45E-07	7.65	59340
3. $HNCO + M \rightarrow H + NCO + M$	6.02E+10	0.85	47,899
4. $NCO + NO \rightarrow N_2O + CO$	1.00E+13	0.00	-390
5. $NCO + O_2 \rightarrow NO + CO_2$	2.08E+04	2.0	6,158
6. $N_2O + OH \rightarrow N_2 + O_2 + H$	2.00E+12	0.00	10,000
7. $N_2O + M \rightarrow N_2 + O + M$	6.90E+23	-2.50	64,760

Units are A=cm-mol-s-K; E_a = cal/mol

The benefit achieved in using the revised reduced mechanism is shown in Exhibits 2.1-6 to 2.1-11. The results in the exhibits are for a residence time of 150 msec and utilize the flue gas composition shown in Exhibit 2.1-4 except the mole fraction of NH_3 (and HNCO) may change for different normalized stoichiometric ratios (NSR). Overall, the agreement between the detailed mechanism and the revised reduced mechanism, for NOx reduction and NH_3 slip, is improved for a range of NSRs, temperatures, and for both NH_3 and urea as reagents.

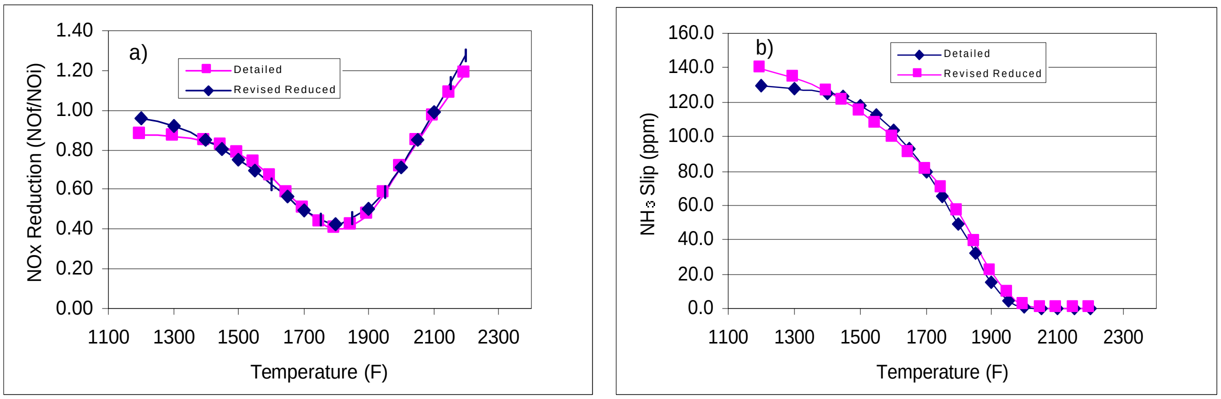


Exhibit 2.1-6
Comparison between the revised-reduced and detailed mechanisms for NH_3 at NSR=1.2
a) NOx Reduction; b) NH_3 Slip

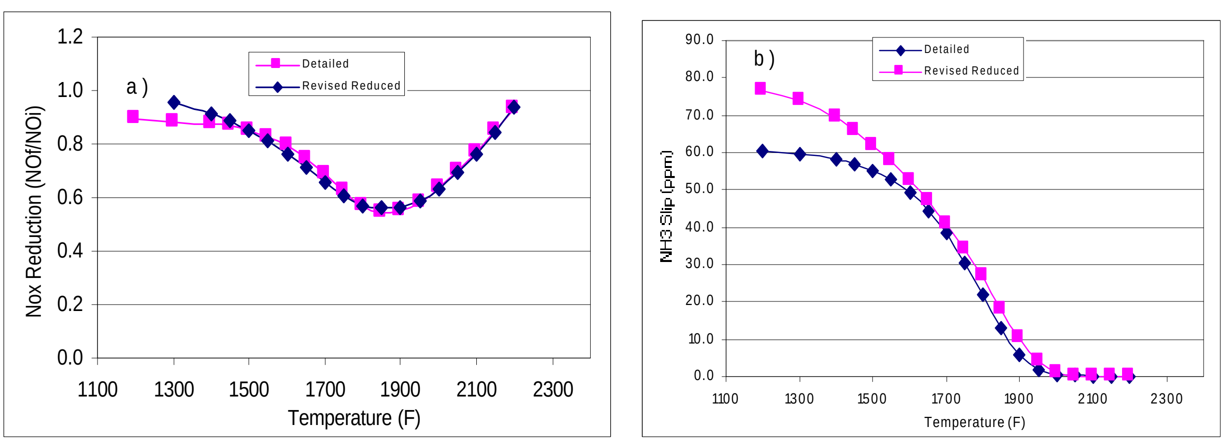


Exhibit 2.1-7
Comparison between revised-reduced and detailed mechanisms for urea at NSR=1.2
a) NOx Reduction; b) NH_3 Slip

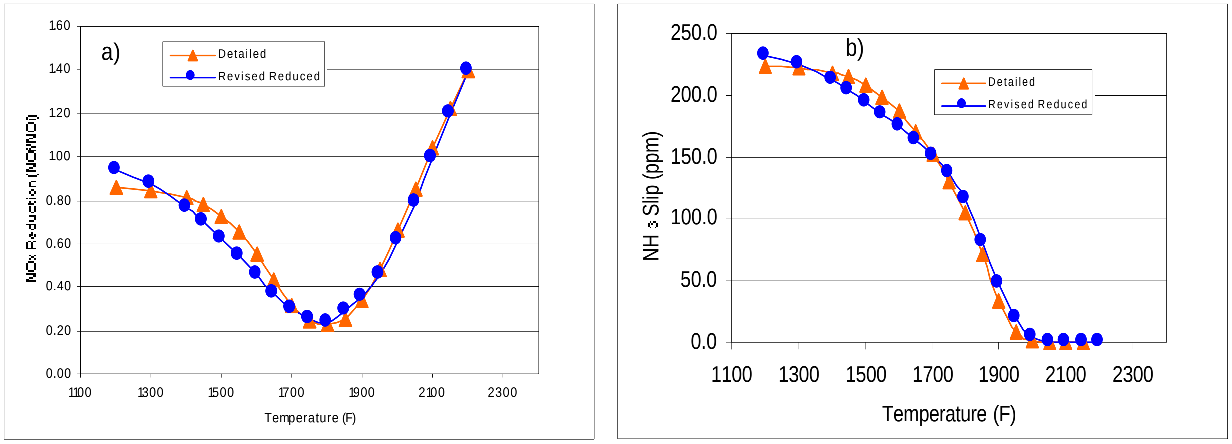


Exhibit 2.1-8
Comparison between revised-reduced and detailed mechanisms for at MSR=2.0
a) NOx Reduction; b) NH_3 Slip

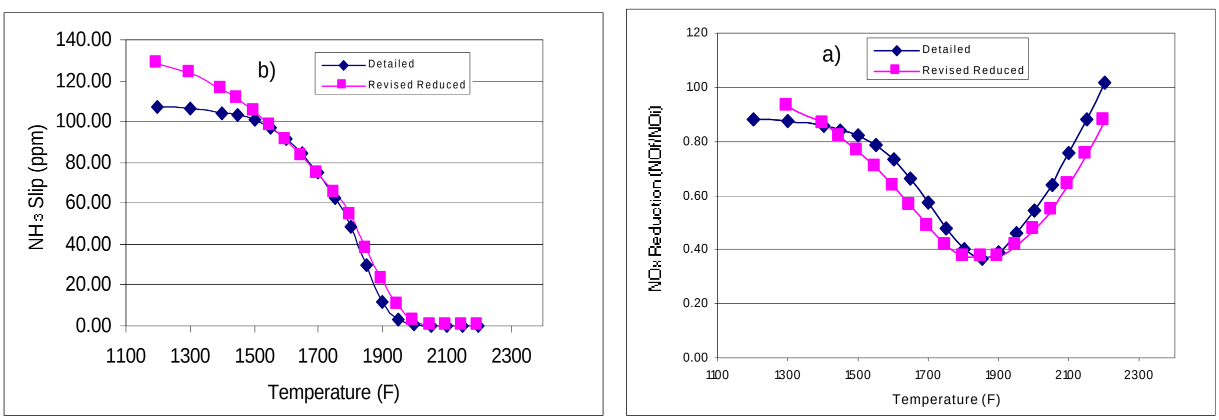


Exhibit 2.1-9
Comparison between revised-reduced and detailed mechanisms for urea at NSR=2.0
a) NOx Reduction; b) NH_3 Slip

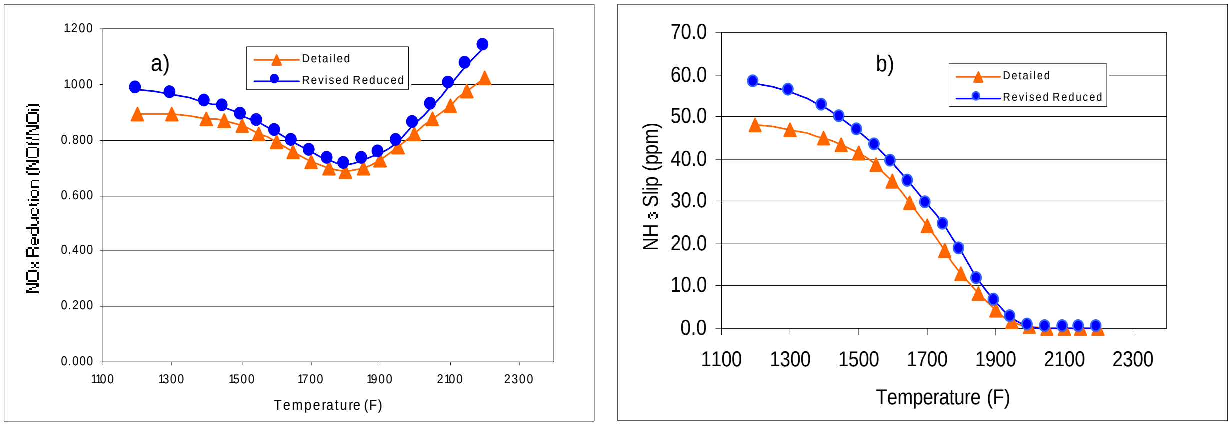


Exhibit 2.1-10
Comparison between revised-reduced and detailed mechanisms for NH_3 at NSR=0.5
a) NOx Reduction; b) NH_3 Slip

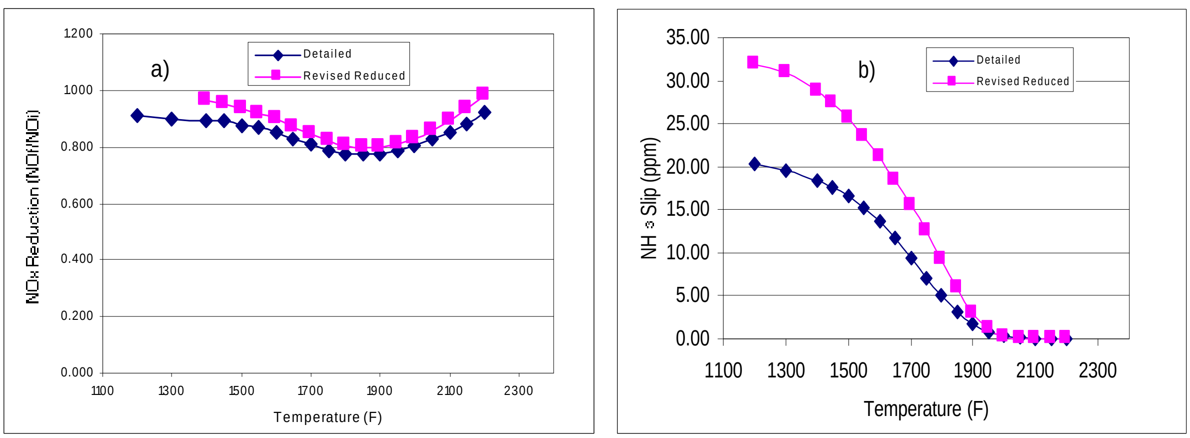


Exhibit 2.1-11
Comparison between revised-reduced and detailed mechanisms for Urea at NSR=0.5
a) NOx Reduction; b) NH_3 Slip

One of the difficulties in using reduced chemical mechanisms is that they are often developed for a specific set of conditions (e.g. temperature, species concentrations, etc) but are then almost always applied to problems that are beyond the limits of the conditions for which the mechanism was developed. The goal of future work is to improve the robustness of the reduced mechanism for SNCR chemistry so that it will be applicable over a wide range of NSR, initial NOx concentrations, temperatures, and CO levels.

References

Brouwer, J., Heap, M., Pershing, D., and Smith, P., Twenty-Sixth Symposium (Int.) on Combustion (The Combustion Institute), Pittsburgh, 1996, PP.2117-2124.

Kee, R., Rupley, F., Miller, J., Sandia Report #8009, September, 1989.

Task 2.2 HITAF Air Heaters

Pilot-Scale Testing

EERC activities this past quarter involved design and procurement, construction and shakedown, and HITAF Testing. Final design is complete for all major system components. Other design and procurement activities have been limited to miscellaneous component and equipment items required to improve temperature measurement in the slagging furnace; reducing SFS pressure swings when bypassing the baghouse or putting it on-line; and reducing SFS process noise. Design and procurement of miscellaneous component and equipment items are complete for now. The remainder of this section discusses system modifications, observations, and results from the SFS operating period completed in December 1998.

Pilot-Scale SFS

Exhibit 2.2-1 is a simplified illustration of the overall slagging furnace system. This exhibit was recently updated to address the removal of the small radiant air heater (SRAH) panel from the slagging furnace. Equipment procurement activities continued this past quarter on a limited basis and will continue indefinitely so that equipment items can be purchased as needed to support HITAF testing. Procurement this past quarter included one muffler to reduce SFS process noise and three optical pyrometers to measure surface and flame temperatures. Electrical work this past quarter included final installation of the three optical pyrometers and miscellaneous maintenance activities in support of overall system operation.

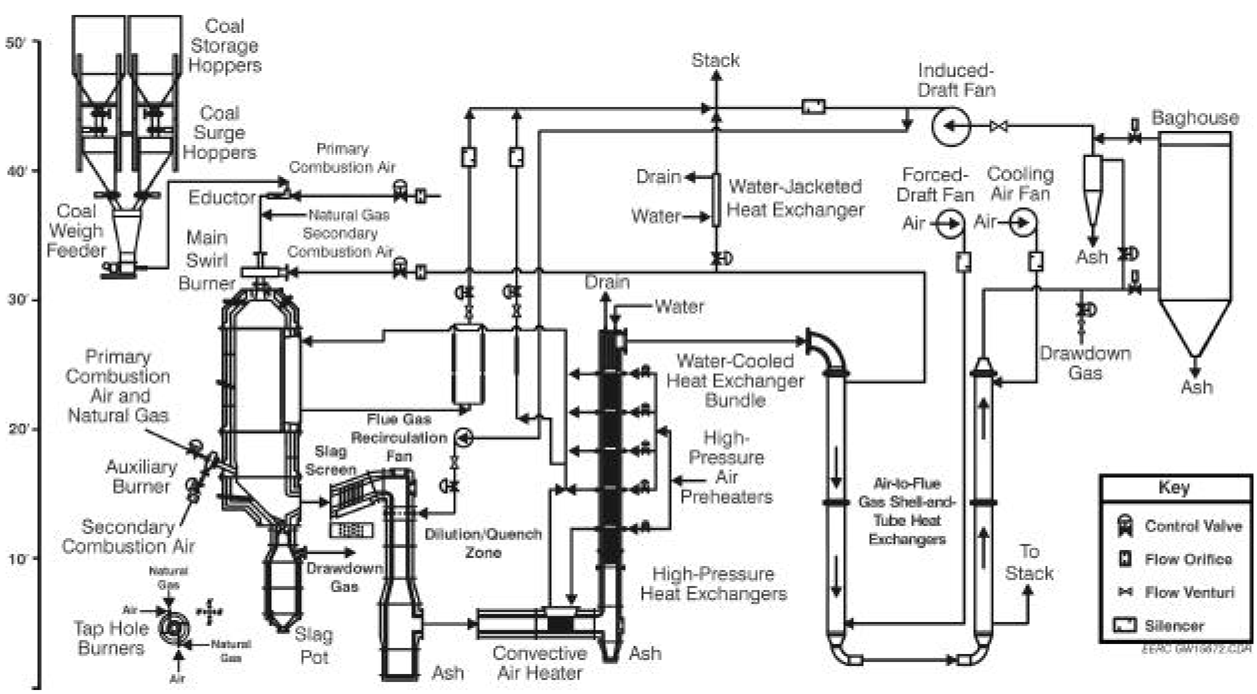


Exhibit 2.2-1 Combustion 2000 Slagging Furnace and Support Systems

Acquisition of optical pyrometers for furnace temperature measurement was necessary to improve temperature measurement reliability. Temperature measurement in the slagging furnace has been successfully accomplished using Type S thermocouples. However, thermocouple deterioration and subsequent failure are a weekly occurrence. It is not unusual to replace $1200 to $1800 worth of thermocouples after each week of operation. Therefore, to improve the reliability of furnace temperature measurement and reduce operating cost, the EERC elected to purchase three optical pyrometers based on the performance of two optical pyrometers evaluated during an August test period. The performance of the optical pyrometers compared favorably with the Type S thermocouples, meeting performance expectations. Two of the optical pyrometers were mounted in relatively permanent locations to measure furnace flame temperature and flue gas temperature near the ceramic tile surfaces of the LRAH panel. These two instruments will replace two Type S thermocouples. The third optical pyrometer was ordered with fiber optics so that it can be used to measure flue gas and surface temperatures at multiple locations in the furnace and slag screen. Final installation of the optical pyrometers was completed in November, following delivery of the third instrument and completion of refractory repairs.

On the basis of SFS operating experience since the LRAH panel was installed in December 1997, EERC personnel determined that mufflers were necessary to reduce SFS process noise within the high-bay facility and emanating from the stack. The July through September quarterly progress report documented steps taken to reduce noise levels and documented a noise reduction of 8–9 decibels outside the high-bay structure. This past quarter, one additional muffler was purchased to further reduce process noise inside the high-bay structure. The new muffler was installed in November in the balance air piping supporting the coal feed venturi. Noise measurements made in December while curing refractory indicated a reduction in process noise inside the high-bay structure of 7–9 decibels, depending on the measurement location.

During the December operating period, no induced-draft (ID) fan trips were encountered when natural gas was fired at the high rate necessary to increase the furnace flue gas temperature near the walls to 3000°F (1649°C) while curing new refractory. This temperature was held for roughly 2 hours. However, neither RAH panel was installed at the time. Whether or not a 3000°F (1649°C) flue gas temperature can be achieved near the furnace walls while firing natural gas with the LRAH panel installed will have to be determined during a future SFS operating period. Based on previous operating experience, the EERC believes that a 3000°F (1649°C) flue gas temperature can be achieved while firing a bituminous coal with the LRAH panel installed.

Slagging Furnace

The pilot-scale slagging furnace design is intended to be as fuel-flexible as possible, with maximum furnace exit temperatures of 2700° to 2900°F (1483° to 1593°C) to maintain the desired heat transfer to the RAH panels and slag flow. Slagging furnace dimensions are 47 in. (119 cm) inside diameter (i.d.) by roughly 18 ft (5.5 m) in total length. The vertically oriented furnace shell was designed to include four distinct furnace sections. The top section of the furnace supports the main burner connection, while the upper middle furnace section provides a location for installation of the LRAH panel. The lower middle furnace section supports the auxiliary gas burner; the bottom section of the furnace includes the furnace exit to the slag screen as well as the slag tap opening. Flue gas temperature measurements have been made using four Type S thermocouples protruding <1 in. (<2.5 cm) into the furnace through the refractory wall and, more recently, using three optical pyrometers. Furnace temperature is also measured using thermocouples located at the interface between the high-density and intermediate refractory layers as well as between the intermediate and insulating refractory layers. A pressure transmitter and gauges are used to monitor static pressures in order to monitor furnace performance. These data (temperatures and pressure) are automatically logged into the data acquisition system and recorded manually on data sheets on a periodic basis as backup.

The refractory walls in the slagging furnace are composed of three layers of castable. They consist of an inner 4-in. (10.2-cm) layer of high-density (14-Btu-in./ft^2°F-hr or 2.0-W/m-K) slag-resistant material, 4 in. (10.2 cm) of an intermediate refractory (4.0 Btu-in./ft^2-°F-hr or 0.6 W/m-K), and a 3.25-in. (8.3-cm) outer layer of a low-density insulating refractory (1.3 Btu-in./ft^2-°F-hr or 0.2 W/m-K). Three refractory layers were selected as a cost-effective approach to keep the overall size and weight of the system to a minimum while reducing slag corrosion and heat loss. Because of its greater structural strength and high corrosion resistance, Plibrico Plicast Cement-Free 98V KK alumina castable was originally used as the inner layer in the top three furnace sections, in the exit of the furnace, and in the top section of the dilution/quench zone. Plicast Cement-Free 99V KK was used in the bottom furnace section (except for the exit), slag tap, slag screen, and transition to the dilution/quench zone because of its even greater resistance to slag attack.

After several weeks of furnace operation, refractory repairs were made to the high-density refractory in the top section of the furnace and the upper middle furnace section. In the top section of the furnace, the Plibrico Plicast Cement-Free 98V KK refractory was replaced with a Narco Cast 60 castable refractory. Replacement was necessary because of the shrinkage found in the Plibrico Plicast Cement-Free 98V KK. The Narco Cast 60 refractory was selected as a replacement because of past success with its use in other furnace systems. Although the Narco Cast 60 is much more prone to slag corrosion, operating experience with bituminous and subbituminous coal had shown that slag deposition was not significant in the top section of the furnace. After over 6 weeks of operation, the Narco Cast 60 refractory appears to be in good shape, although refractory deterioration was evident in the top section of the furnace after 2 weeks of lignite firing. Therefore, the high-density refractory in the top section of the furnace was replaced with a Plibrico Plicast Cement-Free 96V refractory. This material will be less prone to corrosion than the Narco Cast 60 refractory, yet stronger and less prone to shrinkage than the Plibrico Plicast Cement-Free 98V KK refractory previously used in this section of the furnace.

Complete replacement of the high-density furnace refractory was anticipated in the original Combustion 2000 scope of work, although the lifetime of the material was uncertain because of the variable slag deposition that was anticipated. The refractory lasted until after the August test period, after which the decision was made to replace it because of extensive cracking caused by the differences in the expansion and contraction of the inner and middle liners during heatup and cooldown cycles. Actual corrosion of the inner liner was minimal, except for newer patches that were not completely sintered and for areas of flame impingement. The timing worked out well with the need to replace/reassemble ceramic components in the LRAH panel. Exhibit 2.2-2 summarizes properties for refractories used in the SFS.

Slag Screen

The slag screen design for the pilot-scale slagging furnace system is the result of a cooperative effort between EERC, UTRC, and PSI personnel. The primary objective for the pilot-scale slag screen is to reduce the concentration of ash particles entering the convective air heater (CAH). The walls of the slag screen consist of two refractory layers. The inner, high-density layer is a Plicast Cement-Free 98V KK with an outer insulating layer of Harbison-Walker Castable 26. The high-density refractory is 2.25 in. (5.7 cm) thick in the sidewalls and 4 in. (10.2 cm) thick in the roof and floor of the slag screen. The insulating refractory is 3.75 in. (9.5 cm) thick in the sidewalls, roof, and floor. A Plicast LWI-28 refractory was used around the sight ports in the wall of the slag screen. Properties for the high-density and insulating refractories selected for use in the slag screen are summarized in Exhibit 2.2-2. Water-cooled surfaces were installed inside of the refractory tubes to cool the tubes and reduce the erosion/corrosion observed during shakedown tests. Specific details concerning slag screen modifications and performance this past quarter are addressed later in this report.

Dilution/Quench Zone

The dilution/quench zone design was a cooperative effort between the EERC and UTRC. The circular dilution/quench zone is oriented vertically and maintains a 1.17-ft (0.36-m) diameter in the area of the flue gas recirculation nozzles, with the duct diameter expanding to 2 ft (0.6 m) to provide adequate residence time within duct length constraints. The duct section containing the flue gas recirculation nozzles is a spool piece to accommodate potential changes to the size, number, and orientation of the flue gas recirculation nozzles. The vertically oriented dilution/quench zone is refractory-lined and located immediately downstream of the slag screen and upstream of the CAH duct.

Routine cleaning of the dilution/quench zone has been required during each weeklong bituminous and subbituminous coal test period. In order to better monitor and document the slag deposition in the dilution/quench zone, a differential pressure transmitter was purchased and installed in April 1998. Based on observations during the August test period and the frequent cleaning required, the EERC modified the spool piece section of the dilution/quench this past quarter. The specific modification involved the addition of a water-cooled wall around the flue gas recirculation nozzles. This water-cooled wall should embrittle the slag deposits that form in this area, making them easier to remove on-line.

Exhibit 2.2-2
Refractory Properties

Refractory:	Plicast Cement-Free 99V KK/99V[1]	Plicast Cement-Free 98V KK/98V[1]	Plicast Cement-Free 96V KK/96V[1]	Narco Cast 60	Plicast LWI-28	Plicast LWI-20	Harbison-Walker 26
Function	High density	High density	High density	High density	Insulating	Insulating	Insulating
Service Limit, °F	3400	3400	3300	3100	2800	2000	2600
Density, lb/ft^3	185	185	185	145	80	55	66
K, Btu-in./ft^2 °F-hr @ 2000°F	14.5	14.5	14.0	6.5	4.0	NA[2]	2.2
K, Btu-in./ft^2 °F-hr @ 1500°F	14.7	14.7	14.2	6.0	3.0	1.7	1.9
K, Btu-in./ft^2 °F-hr @ 1000°F	15.5	15.5	15.0	5.6	2.7	1.3	1.7
Hot MOR[3] @ 2500°F, psi	650	750	1400	NA	NA	NA	NA
Hot MOR @ 1500 °F, psi	–	–	2000	1000	250	100	110
Cold Crush Strength @ 1500 °F, psi	–	–	10,000	NA	750	400	350
Typical Chemical Analysis, wt% (calcined)							
Al_2O_3	99.6	98.6	95.5	62.2	54.2	39.6	53.8
SiO_2	0.1	1.0	3.8	28.0	36.3	31.5	36.3
Fe_2O_3	0.1	0.1	0.1	1.0	0.8	5.4	0.5
TiO_2	0.0	0.0	0.0	1.7	0.5	1.5	0.6
CaO	0.1	0.1	0.1	2.8	5.7	19.5	7.2
MgO	0.0	0.0	0.0	0.1	0.2	0.8	0.2
Alkalies	0.2	0.2	0.2	0.2	1.5	1.4	1.4

[1] The “KK” designation indicates the presence of fibers that promote dewatering during curing.

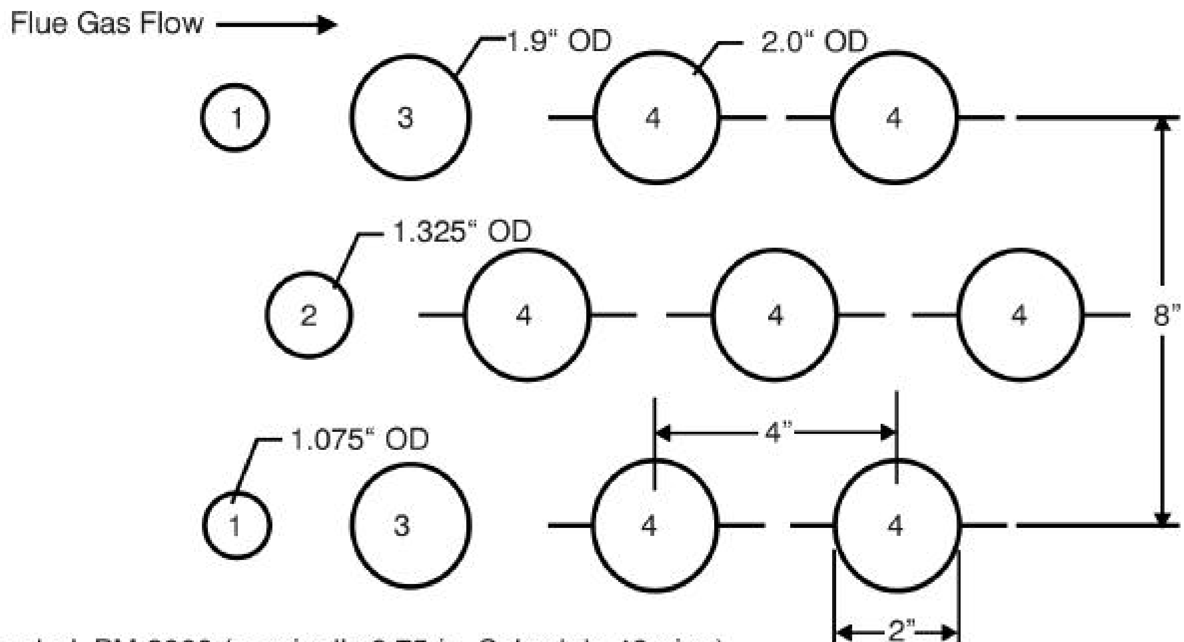
[2] Not applicable.

[3] Modulus of rupture.

Convective Air Heater

The CAH design was a cooperative effort between the EERC and UTRC. It was constructed by UTRC and installed in September 1997. The flue gas flow rate to the CAH tube bank has been calculated to range from 3553 to 4619 acfm at 1800°F (101 to 131 m^3/min at 982°C). A rectangular inside duct dimension of 1.17 ft^2 (0.11 m^2) results in a flue gas approach velocity of 50 to 73 ft/s (15 to 22 m/s) to the CAH. The CAH originally consisted of twelve 2-in.- (5-cm)-diameter tubes installed in a staggered three-row array. The first five tubes in the flue gas path were uncooled ceramic material, with the remaining seven tubes cooled using heated air. The uncooled ceramic tubes were replaced in May 1998 with uncooled stainless steel tubes. Replacement of the ceramic tubes was necessary because they were repeatedly damaged when the tube bank was removed from the duct after the test periods in February, March, and April.

In September 1998, the uncooled tubes were again replaced. The replacement tubes represented three high-temperature alloy types (Incoloy MA956, Incoloy MA956HT, and PM2000) and three pipe sizes (1.5-in. [3.8-cm] Schedule 80, 1-in. [2.5-cm] Schedule 40, and 0.75-in. [1.9-cm] Schedule 40, respectively). Exhibit 2.2-3 illustrates the position, size, and alloy type for the five uncooled tubes.



[1]Uncooled, PM 2000 (nominally 0.75-in. Schedule 40 pipe).
[2]Uncooled, Incoloy Alloy MA956HT (nominally 1-in. Schedule 40 pipe).
[3]Uncooled, Incoloy Alloy MA956 (1.5-in. Schedule 80 pipe).
[4]Air-Cooled, Inconel 625 (2-in. tubing, 0.188-in. Wall).

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Exhibit 2.2-3 Illustration of the New Uncooled Tubes Installed in the CAH Tube Bank

Pilot-Scale SFS Activities

The pilot-scale SFS was fired on natural gas during the period December 7–11. The purpose of the December test period was to cure new refractory in the slagging furnace, slag tap, slag screen, and dilution quench zone. Initial data evaluation has been completed. Therefore, this report summarizes available results and observations for the December test period as well as SFS maintenance and modification activities.

Furnace Refractory Replacement

The high-density refractory liner in the SFS was replaced this past quarter. Replacement was performed at this time because

- ◊ the SFS was not going to be operated for a period of time because of the need to replace the ceramic components in the LRAH;
- ◊ the inner refractory layer had undergone extensive corrosion above the RAH panels and around the furnace exit, and there was severe cracking and some spalling of the furnace refractory in several locations; and
- ◊ the furnace opening previously used for the SRAH needed to be sealed since it was no longer being used.

Exhibit 2.2-4 shows a vertical cross section and several horizontal cross sections of the furnace showing details of refractory installation. Plibrico 96V castable refractory without KK fibers was selected for installation in the top section. The intermediate refractory in this section is tapered inward to help support the high-density refractory exposed to high temperatures in the furnace. An additional cooling coil was installed in the intermediate insulating refractory along the base of this section. Reduced temperatures at the base should decrease shrinkage of the inner high-density refractory at that location and help maintain the structural integrity of this entire section. This is extremely important since the refractory must be self-supporting to allow for its removal for access to the furnace. The 98V with KK fibers that was already available for furnace repairs at the EERC was used to replace the refractory in the bottom exit section. Replacement included most of the horizontal exit to the slag screen and the upper portion of the high-density refractory in this section.

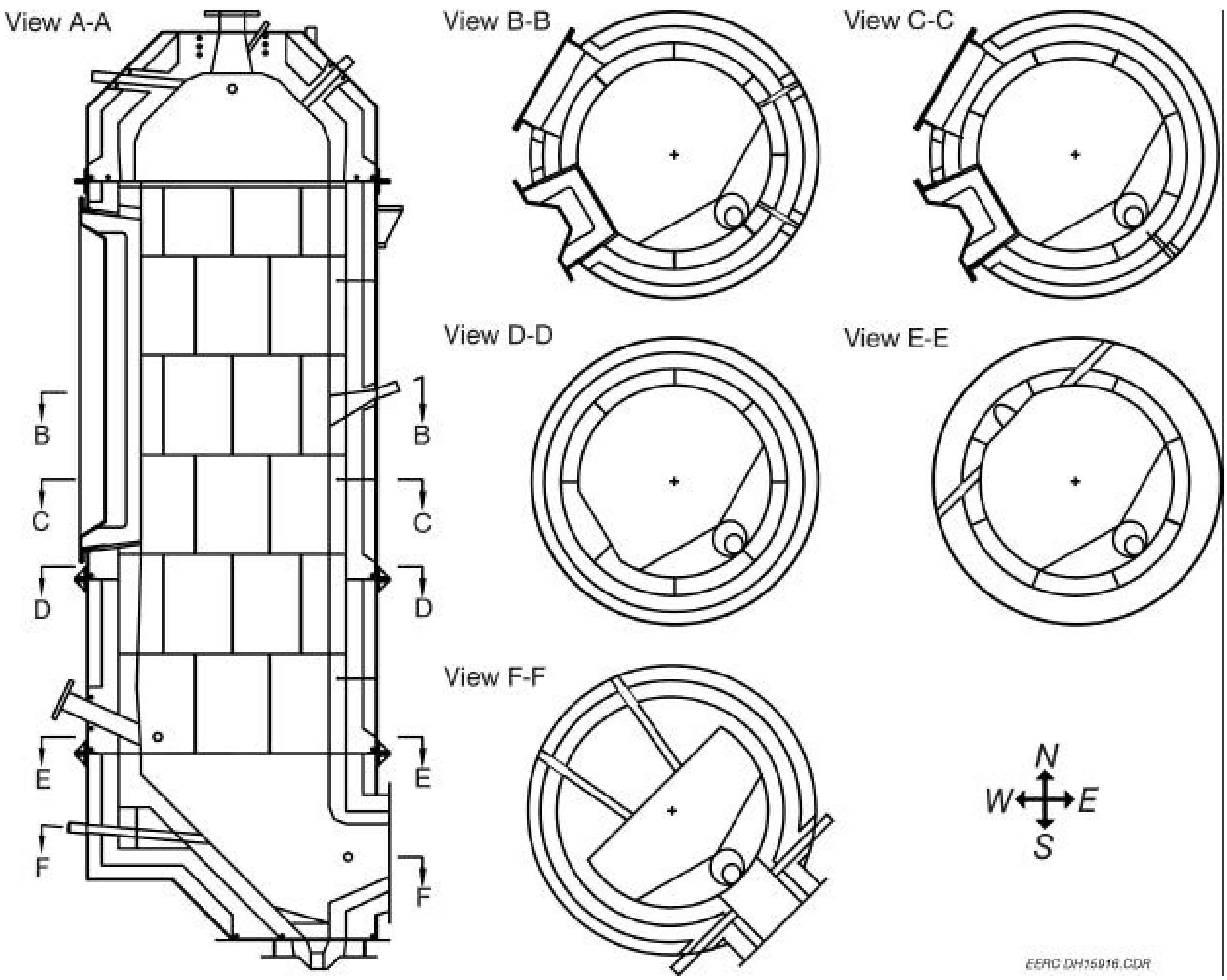


Exhibit 2.2-4 Cross-Sectional Views of Furnace Refractory Layout

Previously, the 98V with KK fibers had been used as the primary high-density refractory layer exposed to slagging conditions in the furnace, with the 99V KK used in the slag tap and slag screen regions. The 99V, with or without KK fibers, is the most resistant to slag attack but structurally weaker than the 98V and 96V. While 96V is a stronger material, it is less slag-resistant when compared with the 98V and 99V. It was decided to proceed with installation of the 98V without KK fibers for the middle two furnace sections which represent the main portion of the furnace. A detailed plan was developed to result in a more stress-free installation for longer life and a design that would not externally induce stresses to the ceramic tiles of the LRAH panel during operation of the SFS.

In the furnace, the intermediate layer of refractory was patched and ground down where necessary to result in a smooth vertical wall to allow movement of the inner high-density refractory layer. The opening for the SRAH panel was poured shut using the same insulating and intermediate materials previously used in the furnace. High-temperature alumina paper, 2 feet in width, was used to line the inside circumference of the intermediate layer to allow the inner high-density refractory to move more freely as it expands or contracts. A 1/8-inch (0.32-cm)-thick layer of low-density polyethylene (LDPE) was used as an additional lining to protect the alumina paper during the refractory pours and to allow for some circumferential thermal expansion of the inner layer of high-density refractory. A series of six refractory pours using the 98V was completed; the first five were 2 feet in height with the last pour 16.5 inches (41.9 cm) high, leaving a 1.5-inch (3.8-cm) gap for vertical expansion. High-temperature alumina paper was used to separate each new layer of refractory installed. In the bottom two pours, eight equally spaced vertical strips of 3/16-inch (0.48-cm)-thick ultra-high-molecular-weight polyethylene (UHMW) were installed. The plastic strips effectively split each 2-foot-high ring of refractory into eight individual blocks in order to permit movement and reduce cracking of the inner shell during heatup and cooldown. The plastic later melted and/or burned out during the first 35 hours of curing at temperatures of <1000°F (<538°C).

Because of a shipping error, all of the high-density refractory installed in the first two pours (two 2-ft[0.6-m] sections) had KK fibers. It was decided to leave these two sections in place and proceed with installation of the remaining refractory sections with the 98V without KK fibers. The balance of the shipment of 98V with KK fibers was returned to the vendor, and the correct shipment of 98V without KK fibers was obtained. For the remaining pours, a slight compromise was made to use up the "old" refractory before it exceeded its shelf life. A 50-lb bag of 98V with KK fibers, the old refractory, was blended with three new 50-lb bags of the 98V without KK fibers.

Six rather than eight uniformly spaced vertical strips of the UHMW polyethylene were required in the upper four pours because of the space taken up by the LRAH door opening. To ensure sufficient room for the LRAH when it is installed, ¾-inch-thick pieces of wood were used on each side of the blank LRAH door. Inadequate room for refractory expansion could induce stresses in the ceramic tiles of the LRAH by putting them in compression.

As the refractory temperature increased during curing, it was initially expected to expand by approximately 1%. Then as the temperature in the furnace approached 3000°F (1649°C), the refractory was expected to shrink about 2% as it underwent a densification process resulting in increased refractory strength. Finally, as a result of cooldown, the refractory was expected to shrink an additional 1%. Normal thermal expansion and contraction should be about 1% for each subsequent heatup and cooldown cycle after the curing process has been completed.

Slagging Furnace Operation

The slagging furnace heating rate during the December test period was limited to 50°F/hr (28°C/hr) while natural gas was fired. Hold points occurred at 250°F (121°C) for 24 hours, 650°F (344°C) for 12 hours, and nominally 3100°F (1705°C) for 2 hours. The slow heating rate was necessary to cure the new refractory in the furnace, slag tap, slag screen, and dilution/quench zone. When the furnace flue gas temperature near the refractory walls reached nominally 3100°F (1705°C), the main burner natural gas-firing rate was maintained at 3.0 MMBtu/hr (3.1×10^6 kJ/hr) for about 5.5 hr, with an auxiliary burner firing rate of 0.5 to 0.65 MMBtu/hr (0.6 to 0.75×10^6 kJ/hr). Subsequently, the main and auxiliary burner natural gas-firing rates were decreased gradually to control the furnace and slag screen cooling rate to100°F/hr (56°C/hr) or less. A summary of furnace and slag screen temperatures is presented as a function of run time in Exhibit 2.2-5 for the December test. Corresponding slagging furnace firing rate data are summarized in Exhibit 2.2-6.

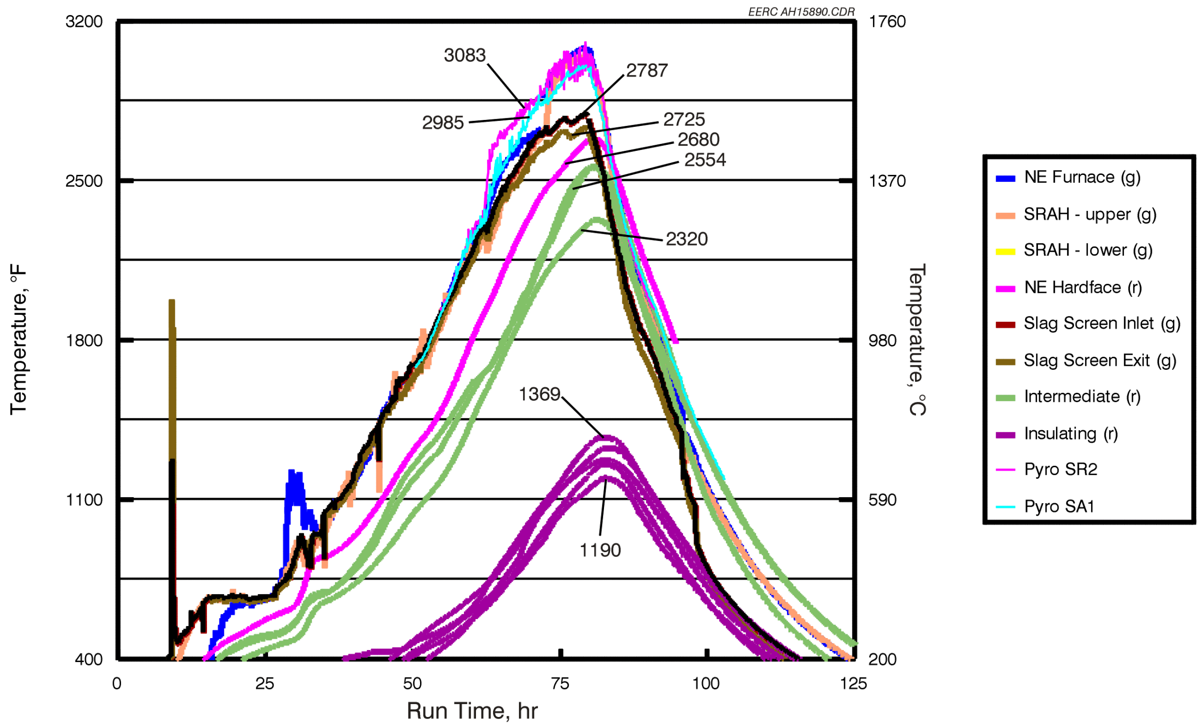


Exhibit 2.2-5 Furnace and Slag Screen Temperatures Versus Run Time for the December Test Period

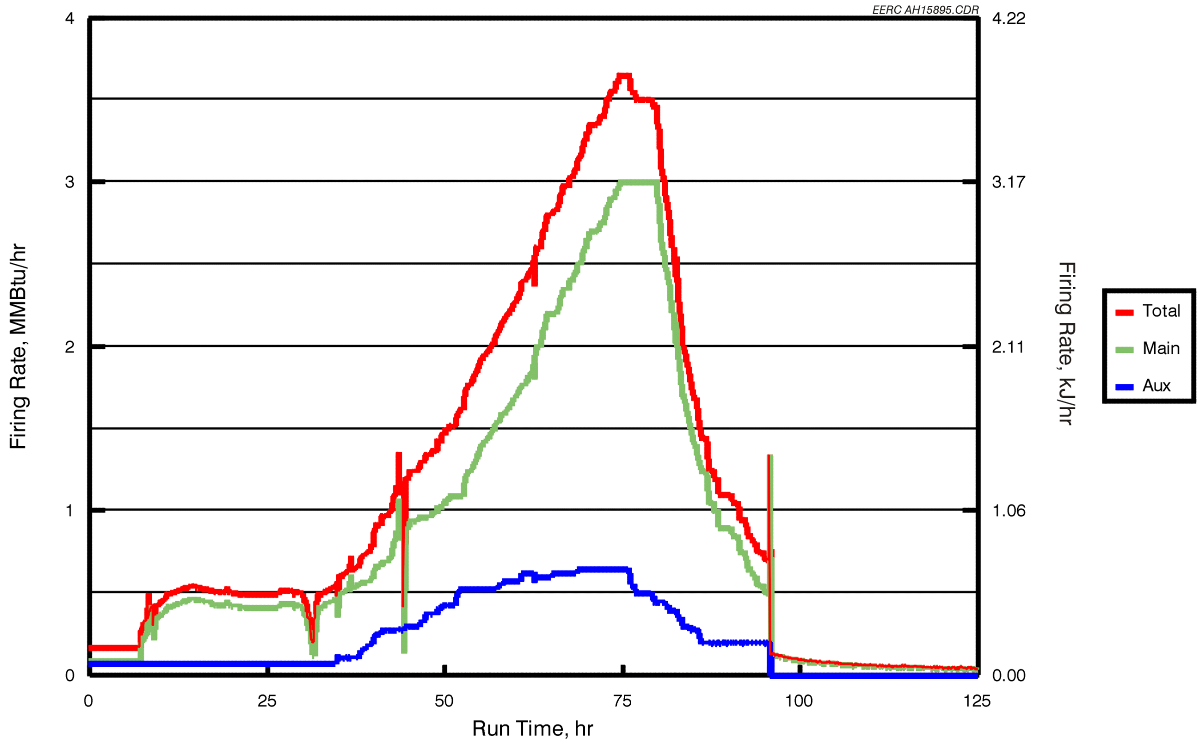


Exhibit 2.2-6 Furance Firing Rate Versus Run Time for the December Test Period

Exhibit 2.2-5 shows that furnace temperatures never actually stabilized for any length of time and that refractory temperatures were lagging behind the flue gas temperatures by 2 to 4 hours. Maximum measured furnace flue gas temperatures ranged from 2985° to 3083°F (1641° to 1695°C) based on a combination of optical pyrometer and Type S thermocouple measurements. Furnace refractory temperatures ranged from 1190° to 1370°F (644° to 744°C) for the hot side of the insulating refractory to as high as 2680°F (1471°C) for the cold side of the high-density refractory. No furnace operating problems were encountered during the December test period.

Inspection of the furnace refractory after the December test indicated that the new refractory was in good condition. Exhibit 2.2-7 presents two photographs of the furnace interior subsequent to curing the refractory. Both photographs show the various lifts that were poured and the location of the vertical spacers. The first photo shows the blank door for the LRAH panel. As the photo indicates, further refractory work will be necessary above the LRAH panel. The second photograph also shows the position of two vertical sight port slots for temperature measurement and observation of the furnace wall and lower tiles of the LRAH panel.

After curing, EERC personnel expected gaps greater than 0.5 in. (1.27 cm) in width wherever the vertical polyethylene strips had been, and that the overall height should have decreased by 2.5 inches (6.35 cm). Selected gaps were to be grouted in using the 98V without KK fibers. However, the vertical gaps had not developed so grouting was not required. Apparently the shrinkage and thermal contraction of the high-density refractory resulted in the reduction of the circumference, forming a gap 0.5 in. (1.27 cm) wide between the high-density and intermediate refractory layers. During subsequent heating and cooling cycles, the high-density refractory layer should expand to reduce the gap between these refractory layers, although it is not clear what effects the coal slag will have on this movement. To correct for the vertical shrinkage that occurred, a 3.5-in. (8.9-cm)-thick layer will be poured to bring the overall height back to within 1.5 in. (3.8 cm) from the top of the furnace. The 1.5-in. (3.8-cm) gap will allow the inner layer to expand upon heating.

A)

B)

Exhibit 2.2-7 Photographs of the Furnace Interior Following the December Test Period

Main and Auxiliary Burners

The main and auxiliary burners performed well during the December test. At this time, the EERC suggests that the slagging furnace be operated using minimum-to-moderate main burner swirl as necessary for a stable flame in order to establish uniform temperatures over the length of the furnace and to minimize NO_x emissions.

Slag Screen

Slag screen flue gas temperatures during the December test period reached a maximum of 2790°F (1532°C) at the inlet and 2725°F (1496°C) at the outlet, respectively. Slag screen operating temperature is selected based on ash fusion data for the fuel to be fired. The EERC tries to operate the slag screen at flue gas temperatures of 100° to 200°F (56° to 112°C) above the fluid temperature of the fuel ash to ensure slag flow from the slag screen to the slag tap.

Exhibit 2.2-8 presents photographs of the inlet and outlet of the slag screen following the December test. The high-density refractory was in good condition at the inlet. However, refractory had spalled off the side walls of the back half of the slag screen. This type of refractory spalling had not been seen previously in the slag screen. EERC personnel believe that the spalling occurred as a result of the wood forms burning out in the slag screen. However, this has not been a problem in the past. Repairs were possible and have already been completed. The dark gray material on the surface of the slag screen tubes is oxidized aluminum pipe used as tube forms. This material will be replaced by slag during the next coal-fired test period. The slag screen tubes will likely always require periodic replacement based on some level of erosion/corrosion and the fuels selected for testing.

A)

B)

Exhibit 2.2-8 Photographs of Slag Screen Tubes Following the December Test Period

Dilution/Quench Zone

During the December test, the dilution/quench zone was effectively used to control the temperature of the flue gas entering the CAH tube bank. However, evaluation of the water-cooled surface added to the dilution/quench zone will not be possible until the next coal-fired test in late January.

Emission Control

During natural gas-fired furnace operation in December, flue gas flow was diverted through the cyclone, and the baghouse was off-line except for about 1 hour. During the course of an hour, flue gas flow was diverted through the baghouse and then again bypassed through the cyclone in order to evaluate the performance of a new controller on the baghouse outlet valve. The purpose for adding the controller was to improve process control when diverting flue gas flow through the baghouse or cyclone and minimize furnace pressure swings. With essentially no differential pressure through the baghouse, the baghouse outlet valve must be opened and closed very slowly in order to avoid furnace pressure swings. With a differential pressure through the baghouse approaching that of the cyclone, a more rapid diversion of flue gas flow is possible. In any event, it should be possible to minimize furnace pressure swings in the future when diverting flue gas flow through the baghouse or cyclone.

Testing of the CAH Tube Bank

The CAH tube bank was installed and initially evaluated during a shakedown test completed in October 1997. Cooling-air flow was adequate for temperature control and to evaluate the performance of the CAH tube bank while firing natural gas during the December test period. Exhibits 2.2-9 through 2.2-11 summarize CAH tube bank surface and flue gas temperatures, cooling-air temperatures, and cooling-air flow rate data for the December test period. Exhibits 2.2-12 illustrates the location of thermocouples in the CAH tube bank, and Exhibit 2.2-13 presents a list of thermocouple descriptions.

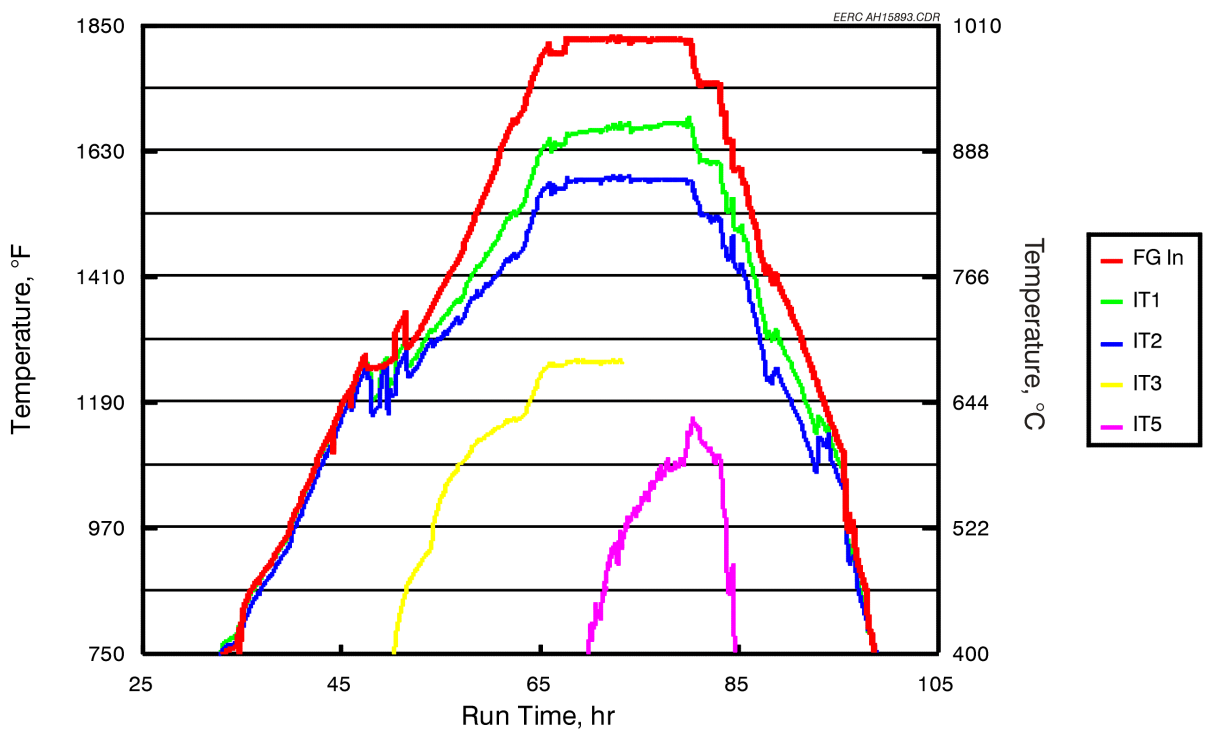


Exhibit 2.2-9 CAH Tube Surface and Flue Gas Temperatures Versus Run Time for the December Test Period

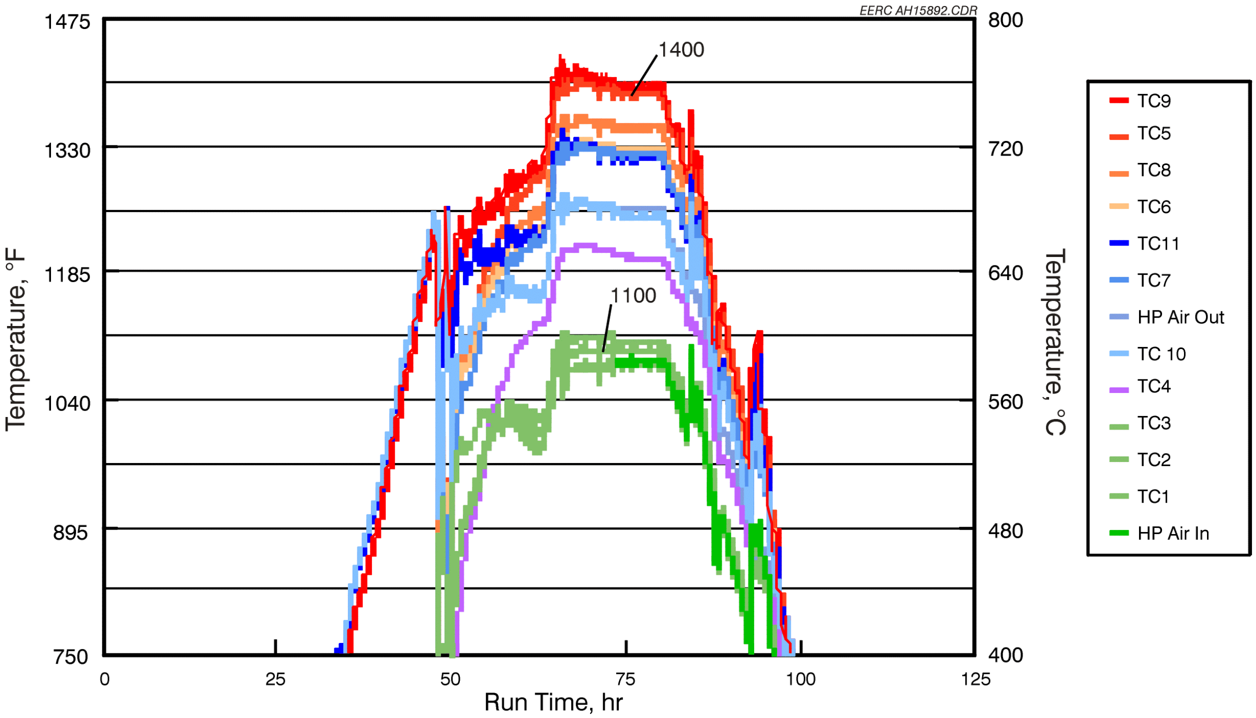


Exhibit 2.2-10 CAH Cooling Air Temperatures Versus Run Time for the December Test Period

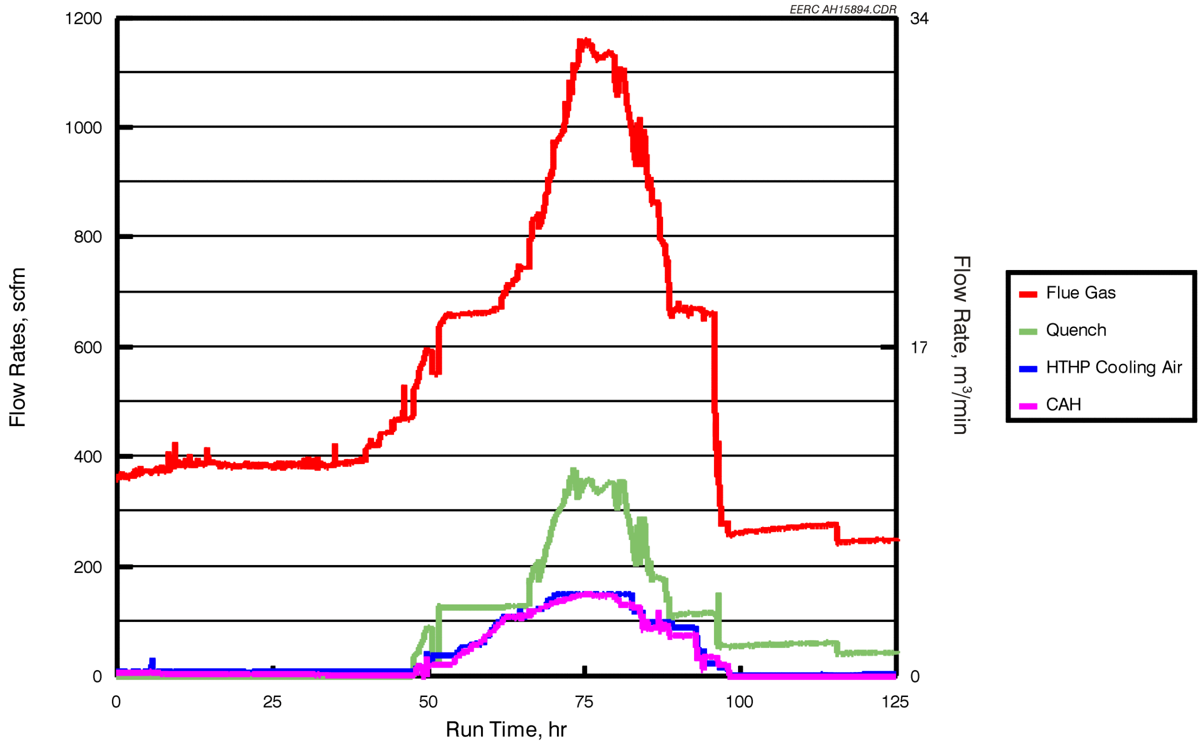


Exhibit 2.2-11 CAH Cooling Air, Quench Gas, and Flue Gas Flow Rates Versus Run Time for the December Test Period

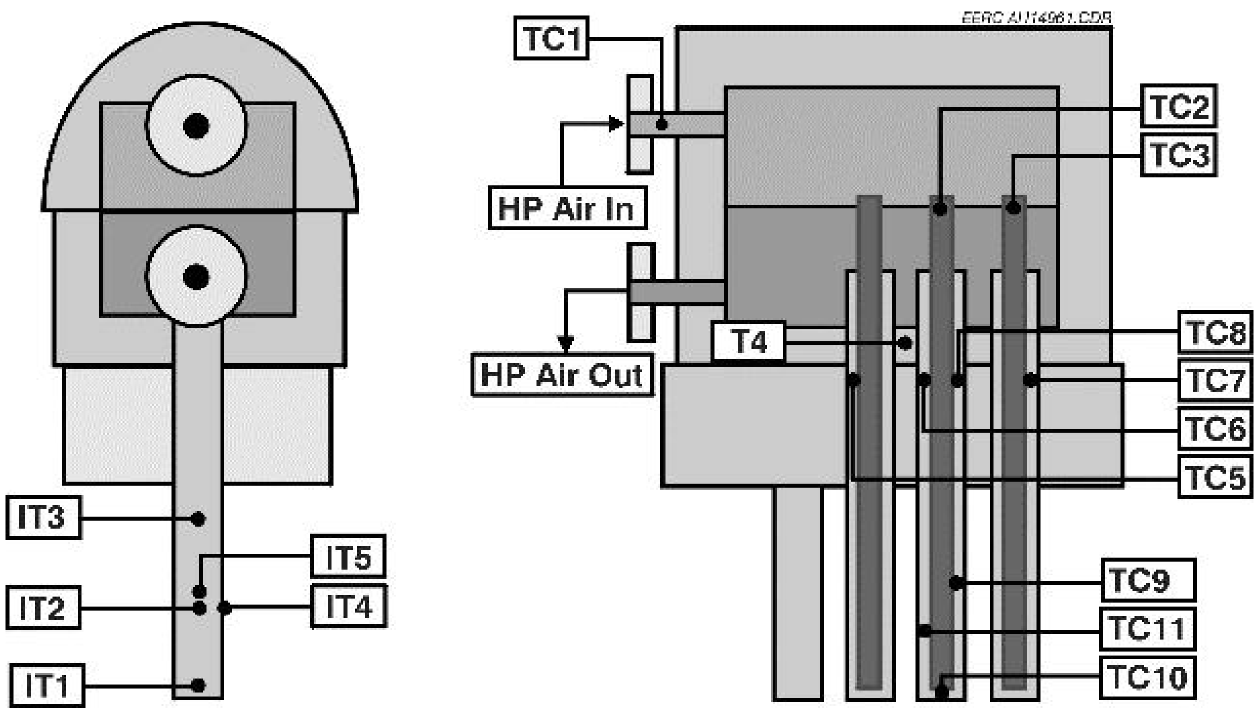


Exhibit 2.2-12 Thermocouple Locations in the CAH Tube Bank

Exhibit 2.2-13
Description of CAH Thermocouple Locations

(Thermocouple locations are illustrated in Exhibit 2.2-12)

Category	No.	Label	Description
Air Inlet	1	CAHTC1	Bulk flow entering the inlet header
	2	CAHTC2	Air entering center tube
	3	CAHTC3	Air entering most downstream tube
Air Outlet	4	CAHTC6	Air leaving center tube
	5	CAHTC7	Air leaving most downstream tube
	6	CAHTC5	Air leaving most upstream tube
	7	CAHTC8	Air leaving side tube
Air in Active Region	8	CAHTC10	Bottom of center tube
	9	CAHTC11	4 in. up outside annulus, center tube
	10	CAHTC9	8 in. up outside annulus, center tube
Tube Surface	11	CAHIT1	1 in. up center tube, facing upstream
	12	CAHIT2	5 in. up center tube, facing upstream
	13	CAHIT3	8 in. up center tube, facing upstream (failed during December test period)
	14	CAHIT4	5 in. up center tube, facing to side (failed during December test period)
	15	CAHIT5	5 in. up center tube, facing downstream
Header Shell	16	CAHTC4	Next to shell on outside, between return air pipes

Prior to the December test, all of the CAH thermocouples were replaced or repaired in conjunction with the installation of the new uncooled tubes. However, two tube surface thermocouples (CAHIT3 and CAHIT4) failed during the December test period. CAHIT4 failed early and CAHIT3 failed at approximately Run Hour 75. No other CAH thermocouples were damaged during the test. Repair/replacement of these thermocouples will be discussed with UTRC personnel prior to the next coal-fired test in late January.

While natural gas was fired and the tubes were clean, heat recovery from the CAH tube bank reached a maximum of nominally 50,000 Btu/hr (52,750 kJ/hr). The cooling-air flow rate was 150 scfm (4.2 m^3/min). The inlet cooling air was 1100°F (594°C), outlet cooling air was nominally 1400°F (760°C), and flue gas was 1850°F (1010°C) entering the CAH tube bank. Exhibit 2.2-14 presents heat recovery in the CAH as a function of run time for the August test.

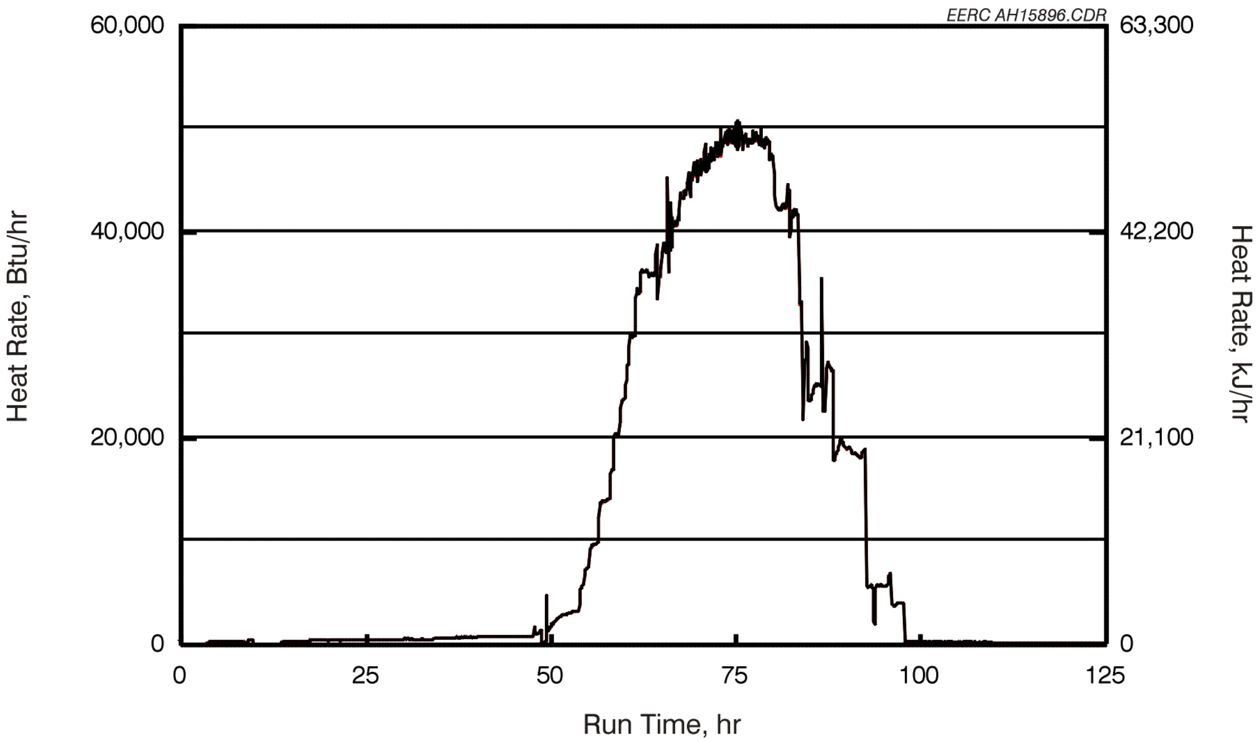


Exhibit 2.2-14 CAH Heat Recovery Versus Run Time for the December Test Period

Testing of the LRAH Panel

Initial shakedown and testing of the LRAH panel occurred in December 1997. Testing of the LRAH panel did not occur this past quarter. Reassembly of the LRAH panel is expected to occur in mid-January. The next coal-fired test to evaluate the LRAH panel is scheduled for the last week of January 1999.

HITAF Air Heater Materials

Refractory Materials for the Radiant Air Heater

During this reporting period, new refractory materials were ordered for the LRAH, which are to be installed in January 1999. New blocks of Monofrax M fused-cast, α/β alumina were ordered and machined into the replacement tiles. The Aurex 30 material for the side supports and top and bottom lentils was not available, and a new source for a comparable composition was located. This material, Spartan CA, is a high alumina with 10% chromia composition. Side rails and top pieces were ordered and fabricated into the required shapes. All parts were available by the end of the year. New candidate materials for the refractory radiation panels are also described.

In addition, the performance of the refractories that were tested in the SRAH and LRAH during 1998 is reviewed. The refractories in the Large RAH panel were exposed to a range of furnace firing-conditions for a total of 1005 hours (620 hrs. on natural gas and 385 hrs. on coal/lignite fuel). The Small RAH panel had been exposed to a range of furnace-firing conditions for a total of 562 hours (344 hrs. with natural gas and 218 hrs. with coal and lignite).

The sectioning of refractory test specimens from various locations in the radiant air heaters is described, and some of the results of an ongoing microstructural examination of the exposed materials are discussed. The effect of the high temperature exposure on the strength of the refractory tile is reviewed.

Replacement Refractories

The materials for all of the refractory parts shown in Exhibit 2.2-15 were ordered and then machined in to appropriate shapes. This included replacement parts of Monofrax M (95% α/β Al_20_3), including the top and bottom pieces and the 3 radiation tiles; and replacement parts of Spartan CA including the top and bottom lentels, the side rails and spacers (not shown in Exhibit 2.2-15). The Spartan CA contains more Al_20_3 than the Aurex 30 that it replaces (83% vs. 65% Al_20_3) and contains less chromia (10% vs. 28% Cr_20_3). However, both these materials have service temperature capabilities in air at temperatures up to 3200°F (1760°C).

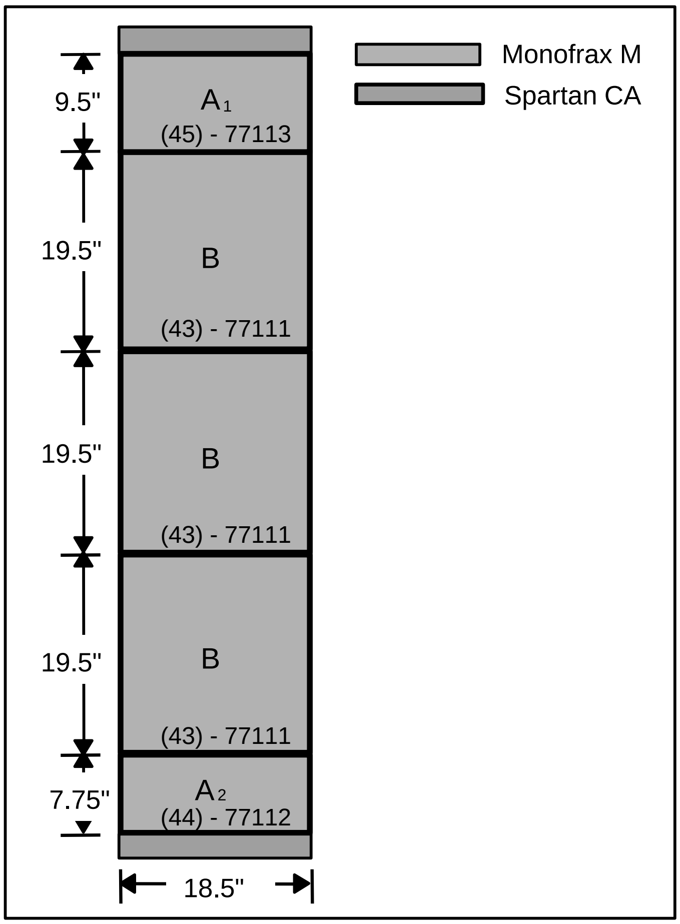


Exhibit 2.2-15 Location of Replacement Refractory Tiles and Supports in the Large Radiant Air Heater (LRAH)

New Refractory Materials

Several refractory companies were approached to produce large, 24" x 19" x 2 - 4" thick (610 mm x 483 mm x 51-76 mm) slabs for machining into the LRAH tiles. However, of those contacted previously, none felt that they could meet all the property requirements. Samples of a new refractory material (a dense, hot-pressed alumina-15% chromia composition) were received recently from another potential vendor for evaluation. Test specimens were prepared for microstructural and mechanical property analysis of the new material. Four point flexural tests were run, and the average room temperature strength was 9.7 ksi (67 MPa) and the elastic modulus was 25.2 Msi (173.7 GPa).

A sample of an experimental, more slag-resistant version of the Monofrax fusion cast materials was received for examination. Monofrax Inc. demonstrated that they could cast slabs in their laboratory of sufficient size that could be machined to make the large LRAH radiation tiles (Tile B, Exhibit 2.2-15). More work is underway to improve the casting process for this size.

Evaluation of Refractory Tiles From the RAH Furnace

Sample Location and History

Refractory tiles were removed from the LRAH and SRAH after various runs in the UNDEERC slagging furnace. Sections of these tiles were sent to URTC for examination and evaluation. The furnace run conditions are summarized in Exhibit 2.2-16. There have been 7 furnace test runs for a total of 1005 hours with the fusion cast refractory tiles in the LRAH and 3 furnace test runs for a total of 562 hours in the SRAH.

Exhibit 2.2-16
Run Summary of Furnace Test Facility at UNDEERC

Date	Fuel	LRAH*			SRAH*			Comments
		Run #	Coal (hrs.)	Gas (hrs.)	Run #	Coal (hrs.)	Gas (hrs.)	
30 Nov – 4 Dec '97	Natural gas	1	- - -	104	- - -	- - -	- - -	Natural gas only
14 –19 Dec '97	Illinois #6 coal	2	35	80	- - -	- - -	- - -	Sudden temperature drop (power failure)
9 – 13 Feb '98	Illinois #6 coal	3	51	60	- - -	- - -	- - -	
16 – 20 Mar '98	Rochelle subbituminous	4	81	32	- - -	- - -	- - -	LRAH – replace top block and tile, and radiation tile
20 – 24 Apr '98	Falkirk lignite	5	50	120	1	50	120	SRAH – replace top tile and top right radiation tile
8 – 12 Jun '98	Center & Falkirk lignite	6	52	61	2	52	61	
7 – 19 Aug '98	Illinois #6 coal	7	116	163	3	116	163	LRAH-Very high temp. test.
	Total		385	620		218	344	
	Total coal & gas		1005			562		

** L = Large, S = Small; RAH = Radiant Air Heater*

Exhibit 2.2-16 shows that a combination of natural gas and various types of lignite and a bituminous coal were used as the fuels. The furnace temperatures were operated above the fusion point of the coal slags, so that they would flow down over the tiles and be collected on a slag screen below. The composition of the slags varied widely with the type of coal/lignite used and reacted differently with the two different tile materials: Monofrax M, an α/β alumina refractory (94.5% Al_20_3 with about 4% Na_20) and Monofrax L, a magnesia/alumina spinel refractory (45% MgO, 54% Al_20_3).

The location of the tiles and support blocks in the LRAH and SRAH, and the samples returned to UTRC for evaluation are shown in Exhibit 2.2-17. Monofrax M was used exclusively in the LRAH because of its high thermal conductivity and refractoriness, and the three center radiation tiles (marked B in Exhibit 2.2-15) were coated with a chromium oxide layer in order to increase the emissivity on the back face adjacent to the heat exchanger tubes. Both Monofrax M and L tiles were used in the SRAH, and their location is also shown in Exhibit 2.2-17. The top left Monofrax M tile (C_L, Exhibit 2.2-15) has a chromium oxide coating on the front (hot) face in order to enhance the resistance to slag corrosion. The support top blocks and side rails (not shown) were made of Aurex 30 (28% Cr_2O_3 and Al_2O_3).

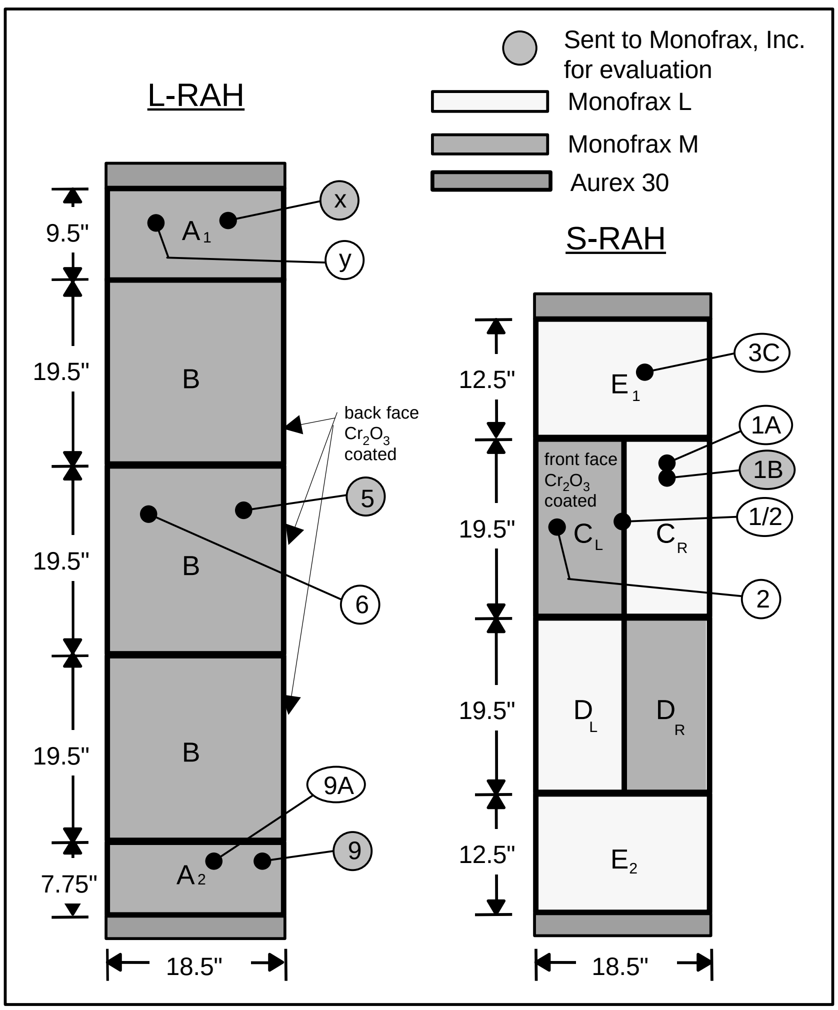


Exhibit 2.2-17. Location of Samples Returned to UTRC for Evaluation

Exhibit 2.2-18A shows the LRAH panel on the left after furnace run No. 4 (see Exhibit 2.2-16), and the two top replaced (white) Monofrax M tiles can be seen. The newly installed SRAH panel is shown on the right side. The dark vertical tile is coated with chromia, and thus appears to be black. Exhibit 2.2-18B shows the slag coated surface of the refractory tiles after Falkirk lignite was used as the fuel (LRAH furnace run # 5, SRAH furnace run # 1).

(A) (B)

Exhibit 2.2-18. (A) Replacement of Top Cross Panel and Radiation Panel in LRAH on left side and installation of SRAH panels on right side after Run No. 4. (B) Slag-coated RAH panels after Run No.5.

Exhibit 2.2-19 shows the test and evaluation plan that is being conducted on the various samples. Some of the work has been completed, and some is continuing into the next quarter. The results of these tests will be used to provide guidelines for improving the refractory materials and performance in future applications.

Exhibit 2.2-19
Sample Description and Test Plan

Sample	RAH	Location (Exhibit 2.2-17)	Material (Monofrax)	Flex. Test	Metallo-graphy	Electron Probe	Report	Source
1A	S*	C_R	L*	√*	√	IP*	4Q98	UTRC
1B	S	C_R	L	---	IP	---	---	MI*
2	S	C_L	M	√	IP	IP	4Q98	UTRC
1 / 2	S	C_R / C_L	L,M	---	√	IP	4Q98	UTRC
3C	S	E_1	M	√	√	√	3+4Q98	UTRC
X	L	A_1	M	---	IP	---	---	MI
Y	L	A_1	M	---	√	√	2Q98	UTRC
5	L	B	M	---	IP	---	---	MI
6	L	B	M	√	IP	IP	---	UTRC
9	L	A_2	M	---	IP	---	---	MI
9A	L	A_2	M	---	√	IP	4Q98	UTRC

* Ö= *completed; S = small; L = large; IP = in progress; MI = Monofrax, Inc.*

<u>Mechanical</u> <u>Properties</u>

Flexural test specimens were machined from some of the returned tile samples, and are shown in Exhibit 2.2-20. These samples were cut sequentially through the thickness of the tiles so that their flat surfaces were parallel to the slag covered surface. The top flexural specimens were in or near the region where the slag had reacted to the tile material; the bottom specimens were remote from the slag layer. The strength data are presented in Exhibit 2.2-21.

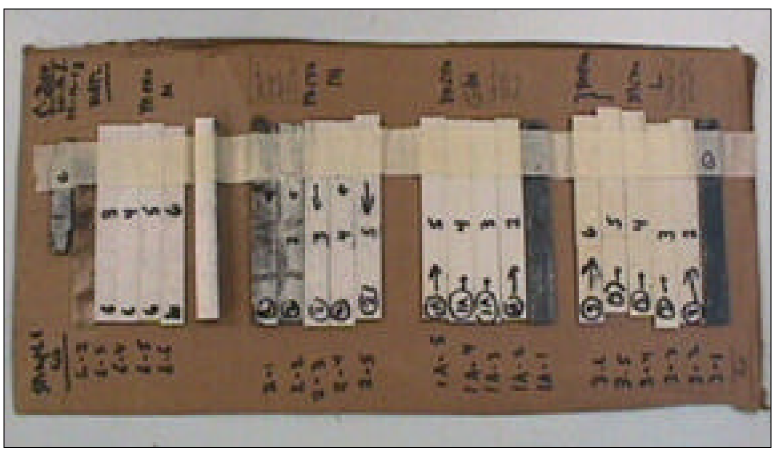


Exhibit 2.2-20. Flexural Test Specimen Machined from the RAH Tiles after Different Furnace Runs

The samples at the left in each group were adjacent to the slag.

Sample 1A, which was a Monofrax L tile (SRAH) that was exposed to one lignite furnace run, had no significant change in strength of specimens near or remote from the slag layer. While these samples appeared stronger than the as-received tile material, the differences are probably not significant, because of the variations in the grain size at various locations in the large cast blocks that were used as the stock to machine the tiles.

Sample 2, which was also a tile from the SRAH, was Monofrax M and had undergone 3 furnace runs with both lignite and bituminous coal as the fuel. Specimens from the discolored, slag-penetrated regions were definitely weaker than the as-received tiles. The top specimen was previously coated with chromia, and a microstructural analysis will be performed to document any reactions or phase changes that might have weakened the material during the furnace run. The material remote from the slag region was significantly stronger, but not as strong as the as-received material. The SRAH had encountered a water leak during this run, which could also have an effect on reducing the strength.

Exhibit 2.2-21. Four Point Flexural Strength of Refractory Tiles

Sample	RAH	Location (Exhibit 2.2-17)	Material (Monofrax)	Flex. Test (As-Received)		Flex. Test (After Run)		Fuel	No. of Furnace Runs	Total No. of Hours
				Ksi	MPa	Ksi	MPa			
1A	S	C_R	L	8.3	57.2	10.9* 10.0**	75.2* 69.0**	G, Lig.	1	170
2	S	C_L	M	3.2	22.1	0.4* 2.3**	2.8* 15.9**	G, Lig., #6	3	170
3C	S	E_1	L	8.3	57.2	3.2* 6.6**	22.1* 45.5**	G, Lig.	1	344
6	L	B	M	3.2	22.1	1.4* 2.8**	9.7* 19.3**	G, Lig., #6	7	1005

*RAH: S = small; L = large; * Test specimen near or in slag reacted zone ; ** Test specimen remote from slag zone*
Fuel: G = natural gas; Lig = Lignite; #6 = Illinois #6 bituminous coal

Sample 3C was Monofrax L, which was also from the first SRAH furnace run, as was sample 1A. However, it was much weaker adjacent to the slag than was the as-received material. Even in a region remote from the slag, the material was weaker (6.6 Ksi, 45.5 MPa). The thermal history and thermal gradients of this cross-piece (E_1, Exhibit 2.2-17) were probably different than those of the top right radiation panel ($C_{R,}$ Exhibit 2.2-17), located just below it.

The Monofrax M radiation panel in the LRAH had undergone all 7 furnace runs, and was exposed to both the lignite and Illinois #6 bituminous fuels. Sample 6 taken from this tile was also weaker in the zone adjacent to the slag layer, but was stronger than Sample 2 adjacent to the slag. The microstructure of this sample is also being examined for differences in the slag-exposed region.

Microstructural Analysis

Metallographic specimens from the samples listed in Exhibit 2.2-17 are in the process of being prepared for optical and electron microprobe analysis. Slices were cut from the tiles C_L, C_R, and A_2 (Exhibit 2.2-17) and were photographed prior to the preparation of metallographic specimens. Some of these slices were further machined into flexural bars, as shown in Exhibit 2.2-20.

Exhibit 2.2-22A shows the slag-covered tiles that were removed from the SRAH after the 3rd furnace run. The rear (cold face) side of a Monofrax top right panel ($C_{R,}$ Exhibit 2.2-17) is shown with the thermocouples still attached in Exhibit 2.2-22B. Three 'thin'-cut slices are shown in this exhibit.

(A) (B)

Exhibit 2.2-22. A) Slag Covered Tiles Removed from SRAH panel after Run No. 3 and B) rear (cold face) side of Monofrax L tile after Run No. 1

The cross-section of one of these slices is shown in Exhibit 2.2-23A, along with a slice of Monofrax M from a left radiation tile ($C_{L,}$ Exhibit 2.2-17). The two slices are positioned as they would be in the SRAH, but are set apart slightly for the photograph. Note that the two overlapping ends are separated by slag, which penetrated the gap between the two ends (Exhibit 2.2-23B).

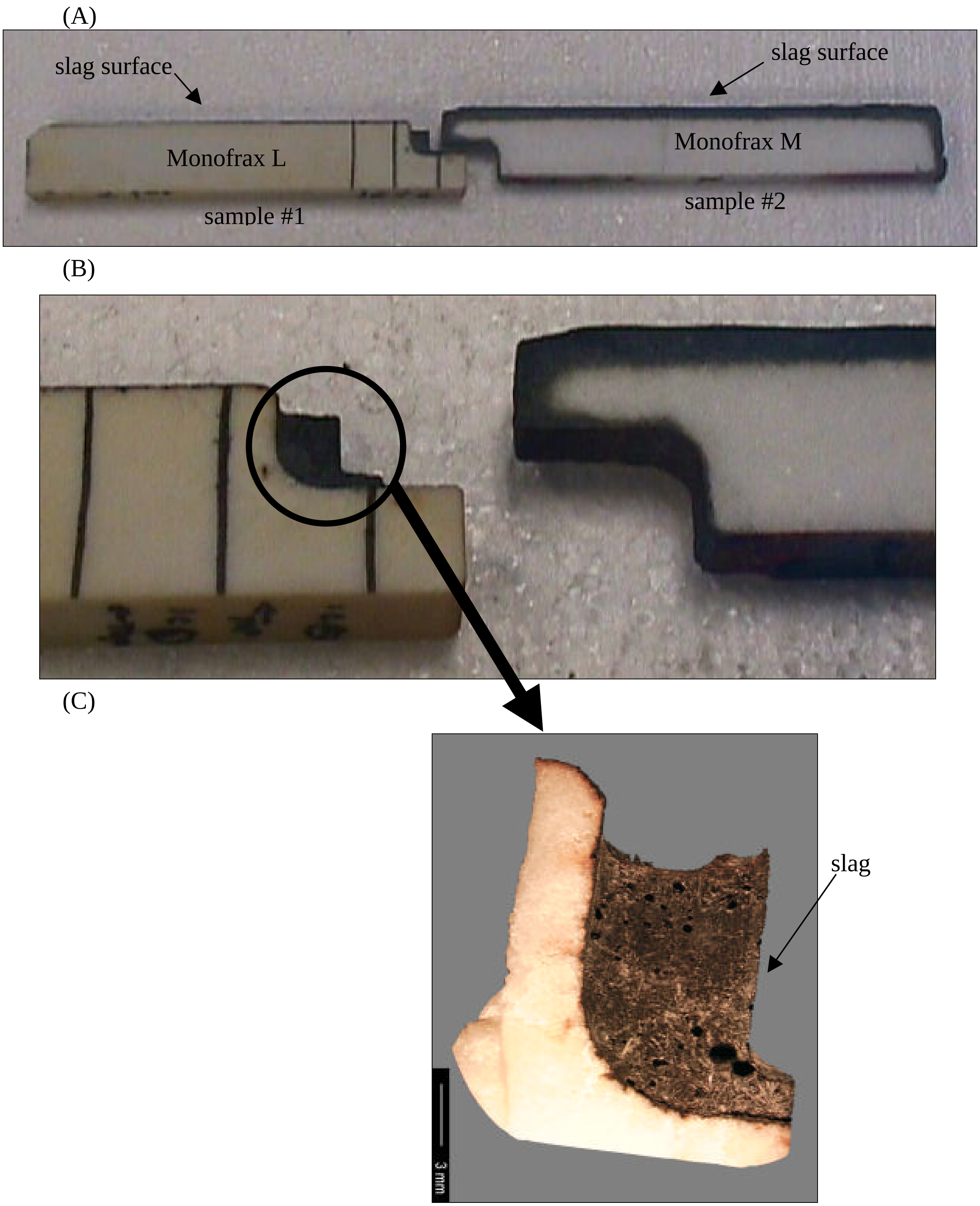


Exhibit 2.2-23. A, B) Cross-Section through Mating Left and Right SRAH Tiles after three Furnace Runs C) Slag Penetration

In the first SRAH furnace run, there was a tight fit between the two tiles. However with subsequent thermal cycles, a gap began to form, until the 3rd furnace run where it had become 9 mm (0.35") wide. A magnified view of the slag in this gap is shown in Exhibit 2.2-23C. Exhibit 2.2-23 also shows that the Monofrax M surface has been discolored to a depth of up to 6 mm (¼") due to reactions with the slag. The Monofrax L surface shows a slag reaction zone only 0.6 mm (1/16") deep. The structure of the slag, the Monofrax L and the interface between the two can be seen in greater detail in Exhibit 2.2-24. Note that the altered zone in the Monofrax L due to reaction with the slag is very thin.

The slag-covered tiles that were removed from the LRAH after 7 furnace runs. Both bituminous coal and lignite were used as the fuels, so that the tile surfaces were exposed to a wide variation in slag compositions. All of the tile refractories were Monofrax M. The bottom cross-piece was the most corroded/eroded of all the tiles. Deep rivulets of slag ran down over the surface cutting grooves into the cross-piece. A section of this region is shown in Exhibit 2.2-25, and the cross-section of the grooves in the Monofrax M with the reacted (discolored) region are clearly visible. Exhibit 2.2-26 shows a section of a groove and the underlying Monofrax M in greater detail. Changes in the morphology and grain structure can be seen as the distance from the reacted zone (groove) increases. The right wall of the groove (Exhibit 2.2-26B) has been heavily attacked by the slag, and consists of laths of the βAl_20_3 grains and interstices filled with the slag. The small white precipitates that decorate the surface of the laths can be seen in Exhibit 2.2-26C. These precipitates are iron-rich particles that formed during the solidification of the coal slags. More details will be available when the electron microprobe analyses of this sample have been completed. While this corrosion, shown in Exhibits 2.2-25 and 2.2-26, appears severe, it only occurs on panels where no heat was extracted and was not considered a part of our test. Furthermore the corrosion was observed only after the runs with lignite at the most severe conditions.

During the next Quarter, the microstructural examination of the various samples described in this report will be completed along with an analysis and evaluation of slag/refractory reactions and refractory performance. Also, the performance of the new refractory tiles and supports in the LRAH will continue to be monitored during the next furnace runs.

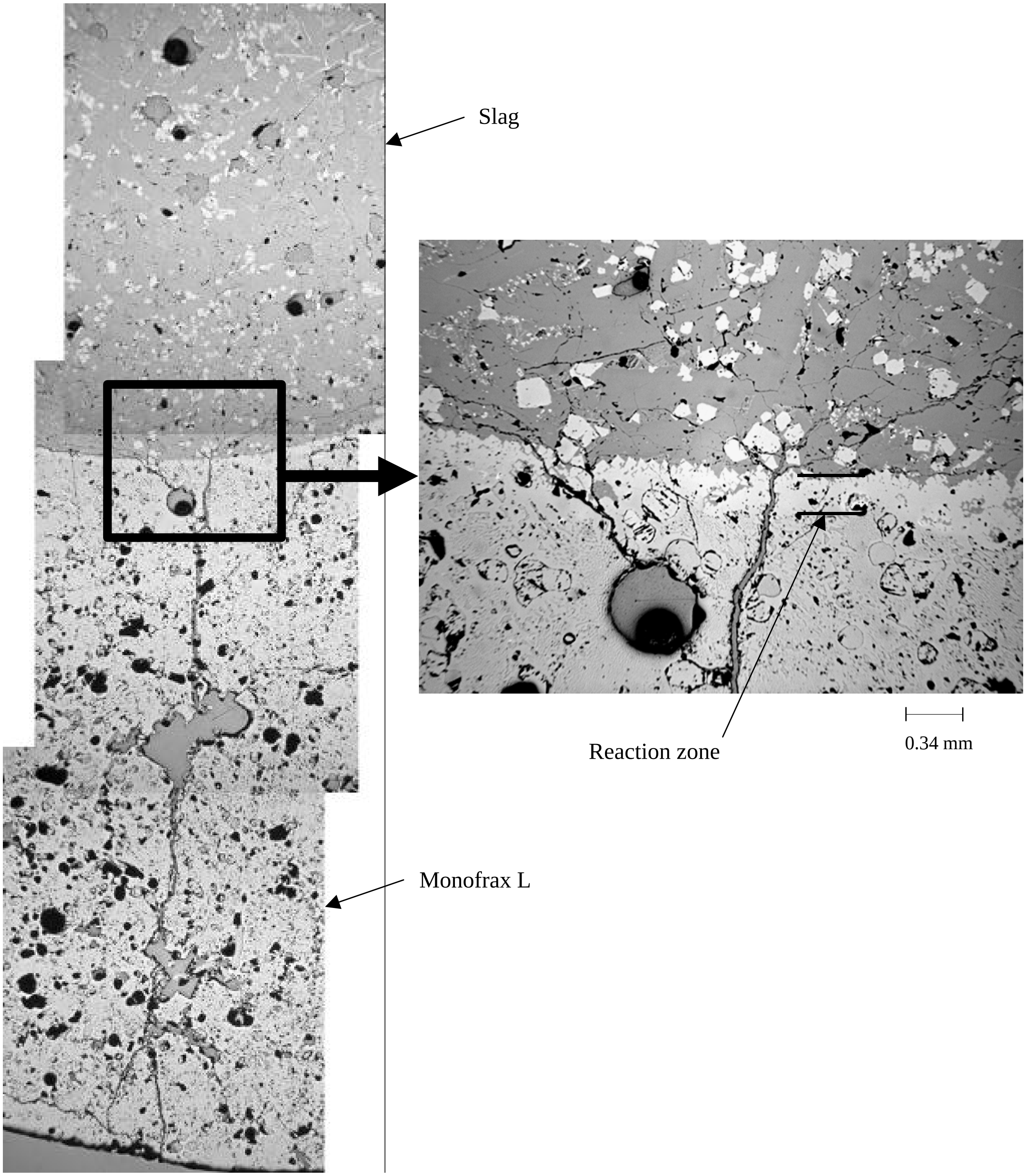


Exhibit 2.2-24. Magnified View of Region in Exhibit 2.2-23C where Slag Contacts the Monofrax L Refractory

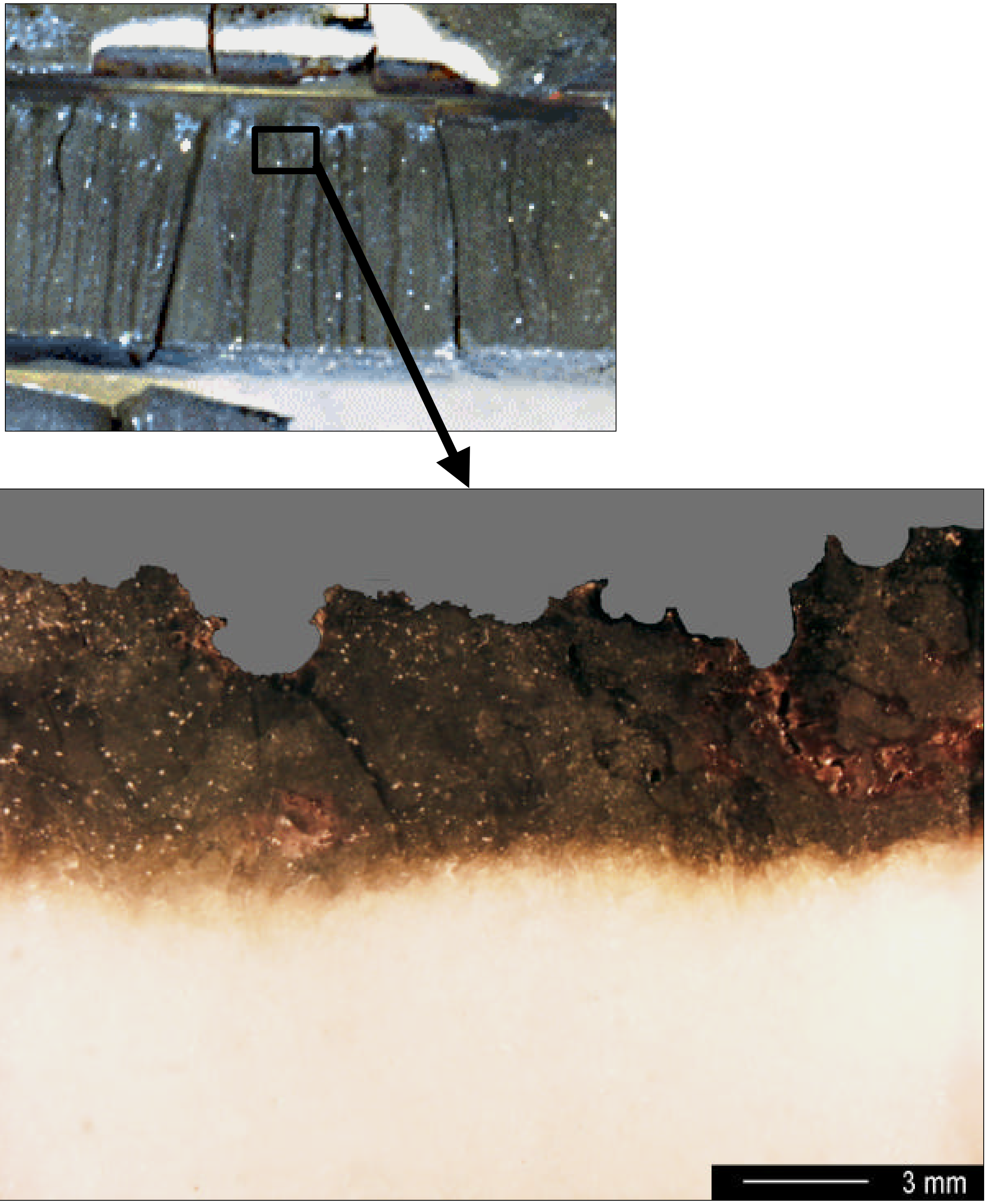


Exhibit 2.2-25. Metallographic Sample of Highly Corroded Region of Monofrax M Tile

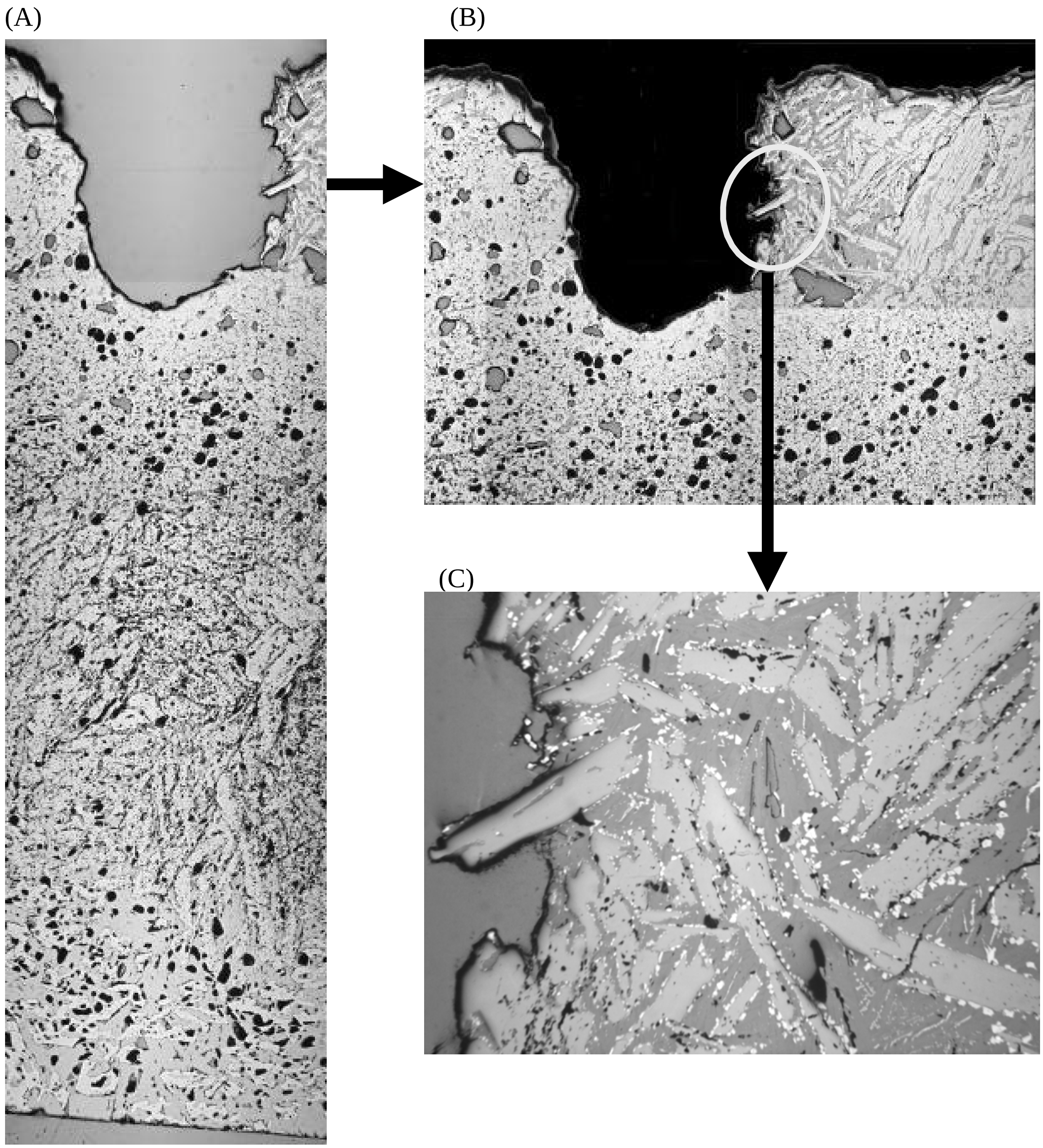


Exhibit 2.2-26. Cross-Sections Through Highly Corroded/Eroded Surface of Monofrax M sample shown in Exhibits 2.2-25 and 2.2-26.

<u>Laboratory- and Bench-Scale Activities</u>

Laboratory-Scale Activities

The tests of lignites in the SFS in April and June of this year showed that new patches of Plicast 98 were severely corroded by the lignite slag, whereas older refractory that had been coated with Illinois No. 6 slag was not corroded. Therefore, laboratory experiments were initiated to find a suitable coating to reduce slag penetration into the refractory. In the October report, we indicated that commercially available coatings were not effective at reducing slag penetration. To effectively seal the pores in the refractory, the coating must initially form a molten phase to seal the pores, then solidify to prevent slag penetration. One way to achieve this is to fire the coated refractory at a significantly higher temperature than the final use temperature, causing the coating to melt and seal the pores, then cooling to use temperature thereby solidifying the coating. A second way of sealing the pores is to use a reactive coating that initially melts, then reacts with the refractory to form a solid phase, preferably expanding significantly. Since it is difficult to fire the SFS at a significantly higher temperature than the actual test temperatures, work has proceeded on the reactive form of coating. To date, eighteen different materials and combinations of materials have been tested as coatings. None of the coatings tested so far completely seal the pores, although several have reduced slag penetration in static tests by up to 35%.

In an effort to understand the variations in the permanent shrinkage measurements for the Plicast materials, dilatometer tests were performed this quarter. Dilatometer measurements to 1600°C (2910°F) were made on Plicast 98 and Plicast 96 refractory materials with and without organic fibers and Plicast 99 without fibers. The initial dilatometer test blocks were 1 in. × 3/8 in. × 3/8 in. and made specifically for the tests. However, measurements with these blocks exhibited poor reproducibility, most likely because they contained highly variable ratios of cement-to-aggregate materials. The larger block size is nominally 2 in. × ½ in. × ½ in., and is cut from a much larger block originally prepared for corrosion testing.

Tests with the larger blocks showed that Plicast 99 without fibers had an average permanent shrinkage of 1.24%. Plicast 98 without fibers had an average permanent shrinkage of 1.32% and 0.98% with fibers. Plicast 96 without fibers had an average permanent shrinkage of 0.49% and 0.0% with fibers; however, the shrinkage up to 1200°C was similar to that for the other Plicast materials. Above that temperature, growth occurred, possibly due to the formation of a mullite phase.

In order to determine the amount of shrinkage that may occur in the blocks over hundreds of hours, shrinkage was also measured in the larger blocks of the refractories used in the dynamic slag application furnace (DSAF) tests. For corrosion tests performed at 1400°C (2550°F) for 100 hours, shrinkage was similar to that measured in the dilatometer at 1600°C (2910°F) for a short time. However, at 1500°C (2730°F), permanent shrinkage in the DSAF was over twice as much, up to 3.4%, as measured at 1600°C (2910°F) in the dilatometer. The data are incomplete, but based on the few sets available, it appears that the greatest amount of shrinkage occurs within the first several hours at high temperature, then continues much more slowly, around 1/50th of the initial rate, over longer periods. It may even fall off parabolically to zero, indicating that prefired blocks could be employed if it is not possible to design around the shrinkage.

In addition to the shrinkage tests, the increase in strength of the Plicast 99 caused by increasing the maximum firing temperature was measured during this quarter. Modulus of rupture testing was performed on Plicast 99 refractory that did not contain organic fibers using standard American Society for Testing and Materials (ASTM) Procedure C-133-97. Two sets of blocks were tested, one set was fired to 2732°F (1500°C) and the second was fired to 2910°F (1600°C). The blocks were held at temperature for 4 hours then ramped down to room temperature and tested. The results show that the blocks fired to 1500°C had an average strength of 2486 psi, and the blocks fired to 1600°C had an average strength of 3468 psi. This indicates that an increase of 100°C in the firing temperature can make a significant difference in the strength and, therefore, the erosion resistance of the material.

Bench-Scale Activities

Two dynamic corrosion tests were completed this quarter using the lignite slags from the SFS lignite tests. The first, which was begun last quarter, was a 100-hour dynamic slag corrosion test at 2732°F (1500°C) on blocks of fused-cast Monofrax L and Monofrax M using the Coal Creek lignite slag. After 100 hours of slag feed, the average measured recession was 0.23 inches and 0.31 inches for Monofrax L and M, respectively. As shown in Exhibit 2.2-27, this is similar to the recession measured for the Monofrax M when testing with the Illinois No. 6 slag. However, Exhibit 2.2-28 shows that there was much less recession for the Monofrax L as compared to the Illinois No. 6 slag test. Exhibit 2.2-29 is a photograph of the blocks after testing with Coal Creek slag.

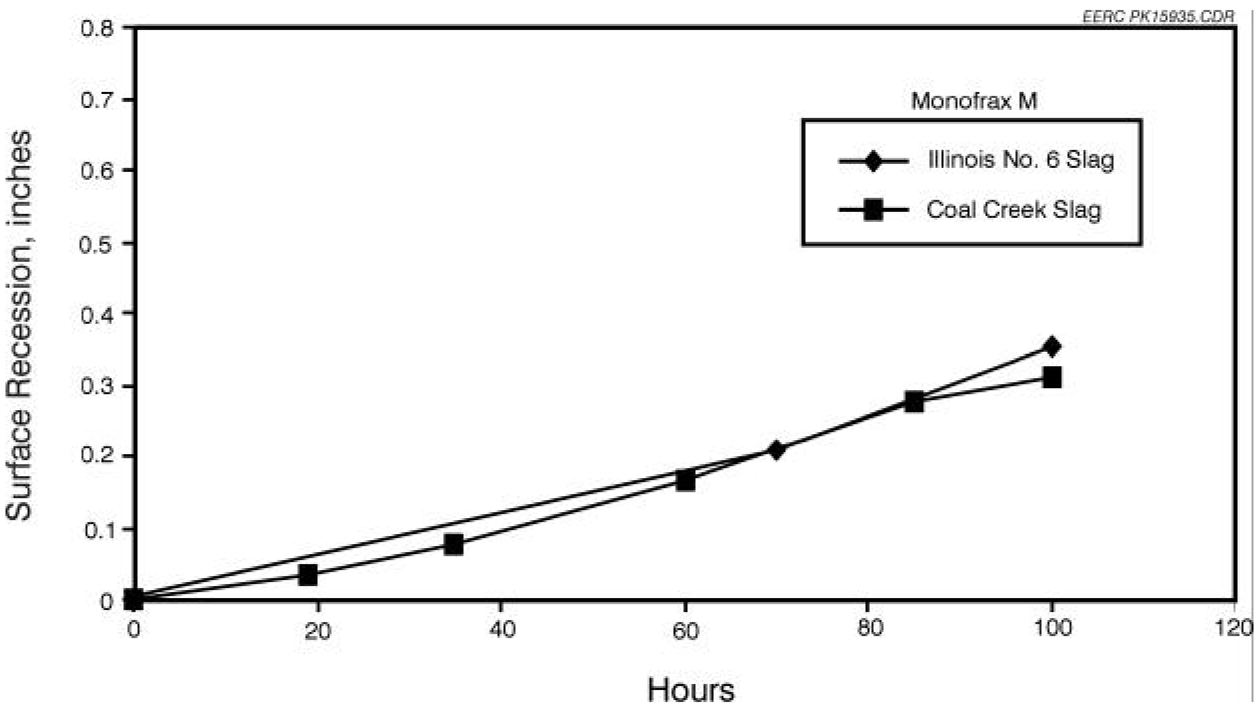


Exhibit 2.2-27 Comparison of Recession Measurements for Monofrax M after Dynamic Corrosion Tests Using Illinois No. 6 Salg and Coal Creek Slag

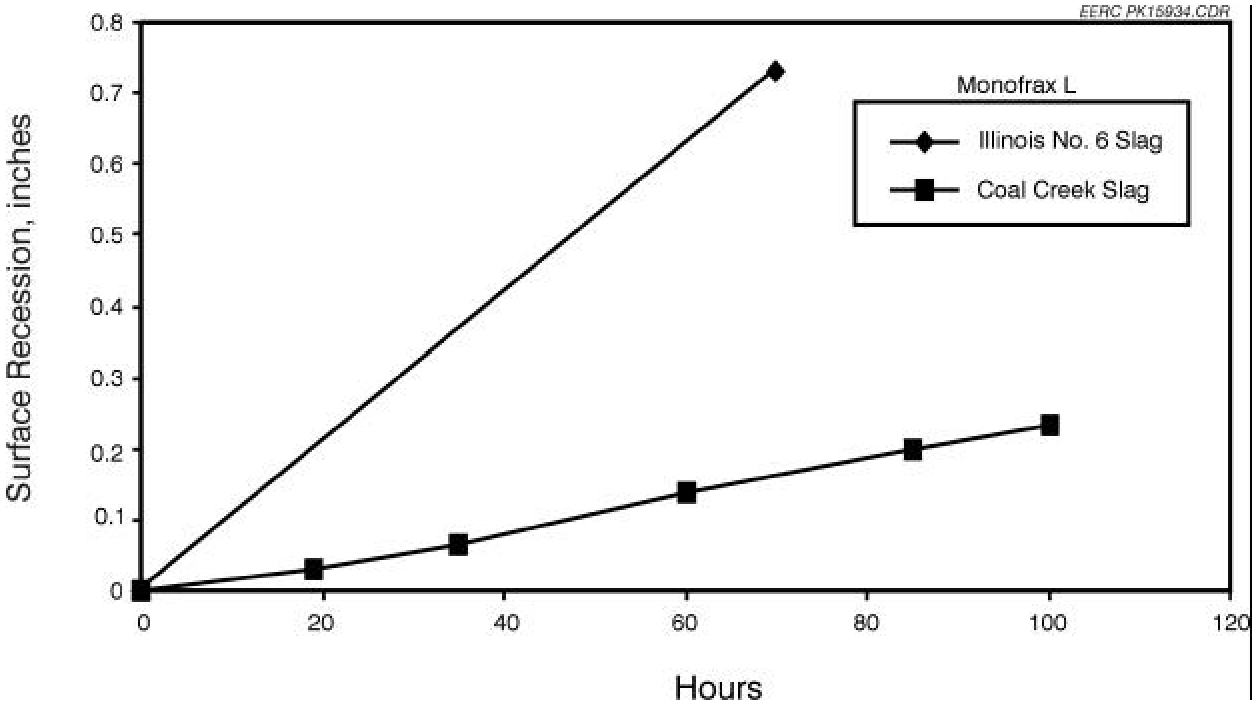


Exhibit 2.2-28 Comparison of Recession Measurements for Monofrax L after Dynamic Corrosion Tests using Illinois No. 6 Slag and Coal Creek Slag

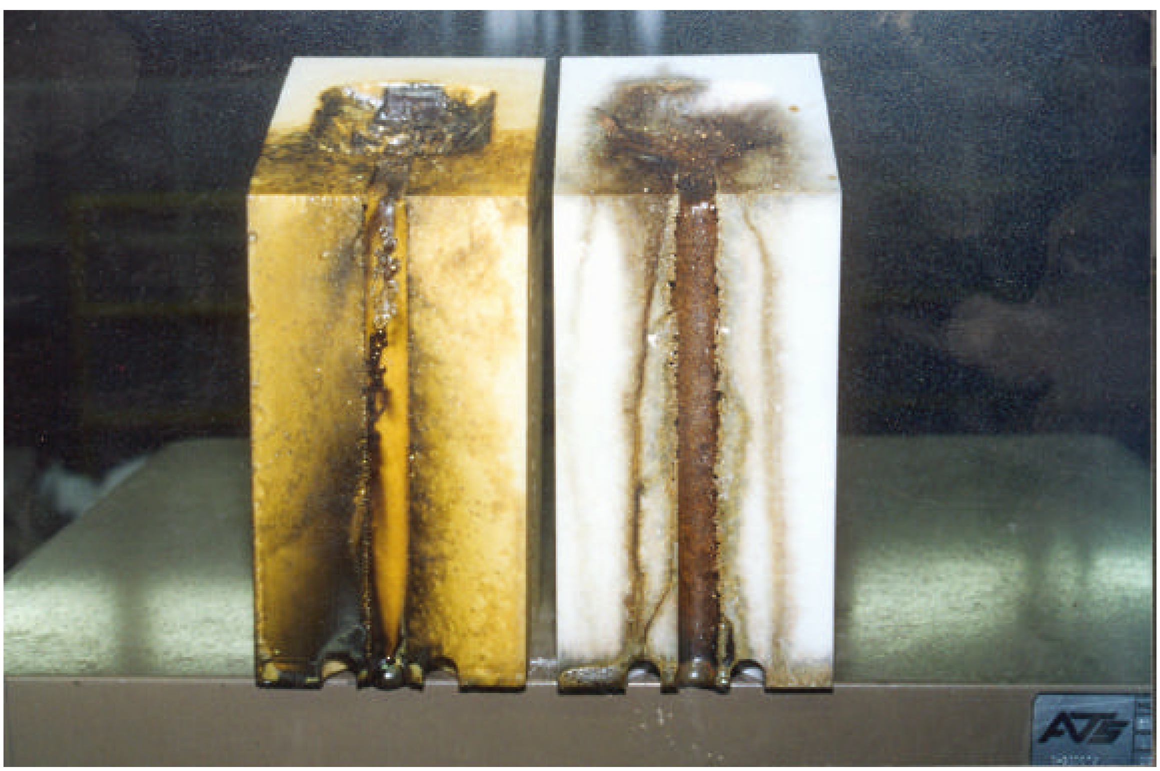


Exhibit 2.2-29 Monofrax L (left side) and Monofrax M (right side) after 100-hour Corrosion Test at 1500°C, using Coal Creek Slag

The second dynamic corrosion test was started on a block of Plicast 99 which had been prefired to 2910°F (1600°C), using Center slag from the second SFS lignite run. The test was performed at 2732°F (1500°C). After 4 hours of slag feed, slag was no longer coming out the exit port on the DSAF. Upon opening the furnace, it was found that the slag had penetrated the refractory; the differences in thermal expansions of the refractory and slag caused the block to expand and crack on the front side as shown in Exhibit 2.2-30. Therefore, the test was stopped.

Exhibit 2.2-30 Plicast 99 after 4 Hours of Slag Feed at 1500°C using Coal Creek Slag

Task 6 Commercial Plant Design

The High Performance Power Systems (HIPPS) electric power generation technology integrates a combustion gas turbine and heat recovery steam generator (HRSG) combined cycle arrangement with an advanced coal-fired furnace. A unique feature of the HIPPS plant is the partial heating of gas turbine (GT) compressor outlet air using energy released by firing coal in the high temperature advanced furnace (HITAF). The compressed air is additionally heated prior to entering the GT expander section by burning natural gas. Thermal energy in the GT exhaust and in the HITAF flue gas are used in a steam cycle to maximize electric power production. The HIPPS plant arrangement is thus a combination of existing technologies (gas turbine, heat recovery units, conventional steam cycle) and new technologies (the HITAF including its air heaters, and especially the heater located in the radiant section of the furnace).

Market Study for HIPPS Technology

<u>HIPPS Market Study Summary</u>

The HIPPS market study examines the current state of electric power generation in the United States, and forecasts for future changes to the industry. The Energy Information Administration (EIA) of the U. S. Department of Energy was the source of most raw data. The EIA data is collected from utilities, and usually does not reflect power generation by independent producers or others outside the regulated utility field. Seventeen States were selected as a focus of the study, and that selection was reduced to seven States where the effort can be concentrated to market the HIPPS technology. HIPPS is shown in the study as being competitive with other power generation technologies, including gas turbine combined cycle power plants.

Estimates and Forecasts for the HIPPS Market

The following significant issues were used in the study, or result from estimates made in the study.

Market size:

- 403,000 megawatts of capacity will be required by 2020 in the U. S. to replace older units and provide for growth. Of that total new capacity, 49,000 megawatts is forecast as coal-fired. Consequently, for the HIPPS market to have the best opportunity to grow, HIPPS will have to compete with, and capture some of the forecast natural gas-fired capacity.
- The market for HIPPS could range from 8,000 megawatts (20% of the planned coal-fired additions) to 80,000 megawatts (about 20% of the total capacity addition).
- The megawatt range above equates to a cost range of from about $6 to $60 billion (in 1997 dollars) over the period from now to 2020.

Market timing:

- Because of the planned retirements of existing units, more than half of the added capacity will occur in the 2010 to 2020 period. This allows time for HIPPS to demonstrate its performance and economic advantages.

Repowering Market:

- There are several thousand megawatts of opportunity for HIPPS in the near term (now to 2006) as utilities plan to change the capacity of existing units. (Data about repowering beyond 2006 was not available and markets were not estimated.)
- There are unknown opportunities in the non-utility power generating industry if HIPPS can show successful experience and competitive costs compared with other technologies, including gas turbine combined cycle.

Location:

- While not examined in detail, there may be major opportunities for HIPPS in the European and Asian markets where fuel prices and environmental limits drive power generation plants to the most efficient systems.
- In the U. S., the States of Ohio, Indiana, Pennsylvania, Illinois, Missouri, Tennessee and Wisconsin were selected as having the best conditions for HIPPS to enter the power generation market.

Competitive Standing:

- From estimates made for the conceptual plant design, HIPPS is clearly more economical than integrated gasification combined cycle and pulverized coal-fired technology on both a capital cost and cost of electricity basis.
- While having a higher capital cost, HIPPS is also competitive with gas turbine combined cycle plants based on the present value cost of electricity calculated in a range of power generation scenarios.
- The cost of electricity for HIPPS is competitive with the average prices paid for electricity in the 17 States examined by the study.

Vital Statistics

A large amount of data was examined during the study with a lesser, but still significant amount reported. The items below further distill the data to illustrate areas of special importance to the forecasts of a HIPPS market.

- The installed coal-fired capacity of the U. S. is 302,000 megawatts, or about 43 percent of the Nation’s total capacity in 1997. About 30 percent of the coal-fired capacity began operation in, or prior to 1960.
- In general, the utility industry is a low growth area of our mature economy. Some of the low growth of electric power demand can be allocated to efficiency and other advances in generation and consumption technologies.

The study selected 17 States in the U. S. to focus the work of estimating the market for HIPPS technology power plants. Data about the 17 States was examined to show:

- Some 44,500 megawatts of coal-fired capacity started operation in 1960 or earlier.

- As indicated by fuel (coal and natural gas) use, growth in the 17 States has a wide variation. The variability may indicate areas of opportunity in an overall slow growth industry.
- Fuel prices in the 17 States follow a National trend for coal price to decline while natural gas price increases.
- Average electricity prices charged to the ultimate consumers in the 17 States ranged from 4 to 8 cents per kilowatt hour (kWh).
- The EIA forecasts that (nationally) plants with an operating and maintenance cost greater than 4 cents per kWh will be retired in the next decade.
- There are some 5,000 megawatts of coal-fired capacity planned for addition during 1997 to 2006 in the U. S. Four thousand megawatts is planned in the 17 States. For natural gas-fired plants (gas turbines and gas turbine combined cycle) the Exhibits are much higher; 32,000 megawatts for the U. S. and 22,000 megawatts for the 17 States.
- In addition to the planned additions in the 17 States, some 6,200 megawatts are planned for changes to their installed coal-fired capacity.

Introduction and Background

A market study using published data was performed as part of the work to produce a commercially viable design for the HIPPS technology. The study assesses how present U. S. industry conditions and utilities' plans for new generation and changed or repowered generation may impact opportunities for HIPPS to enter the power production market.

The study used data from several Energy Information Administration (EIA) databases where electric power and fuel data is collected from utility inputs. The EIA data has been reorganized and consolidated to evaluate the HIPPS market. The following major sets of data are explored in the study.

- Selection of States by installed coal-fired generation capacity and coal use: To narrow the scope of the study, 17 States were selected for more extensive study based on their use of coal for power generation.
- Aging of steam generation units: As a gauge of possible repowering and greenfield HIPPS applications, the age of existing power plants in the 17 States was documented.
- Power generation growth: States with higher growth rates may be more likely to require adding generation capacity and using HIPPS. Power generation growth rates are calculated from EIA data.
- Fuel prices: The difference in prices between utility natural gas and coal fuels is a crucial parameter for HIPPS to compete with other new power generation and repowering technologies. The price rate change was determined for the States as another factor in the potential market for HIPPS.
- Cost of Electricity/ utility revenue: The COE for HIPPS has been estimated in earlier tasks. The HIPPS COE is considered in perspective with existing plants. As the cost of

electricity is not available by State, prices are used to assess the market opportunities for HIPPS versus existing price structures.

- Planned generation capacity additions: The EIA data includes utilities' estimates for adding capacity. This information is used to help estimate the size and location of HIPPS markets.
- Planned utility changes: EIA also provides the utility information on repowering, retirement, reactivation and increases/decreases planned for existing units. This data is reported and used to estimate the HIPPS market.

Overview of U. S. Utility Power Generation

United States electric utility power generation capacity totaled 712,033 megawatts as of January 1, 1997. Some 12,800 megawatts of this total are classified as inactive. Net generation for 1997 was 3,123 billion kilowatt hours (kWh); an increase of 1 % from 1996. Categorized by energy source, the totals are in Exhibit 6-1.

Exhibit 6-1
Overview of Utility Capacity and Generation

Energy Source	Megawatts Capacity	Percent of Total Capacity	Percent of Total Generation
Coal-Fired	302,523	42	57
Gas-Fired	142,566	20	9
Nuclear	100,756	14	20
Renewables	75,448	11	11
Petroleum	69,480	10	2
Pumped Storage Hydro	21,110	3	1

The capacity data included almost 4,800 megawatts of new (added in 1997) capacity, with this added generation split as 34 % coal; 36 % gas; 23 % nuclear and 7 % from other energy sources.

Renewables (water, geothermal, solar, biomass and wind) total about 1 % of the capacity and less than 1 % of the generation when conventional hydroelectric is separated from the renewables category.

The data reviewed in this report is largely from EIA utility data. However, non-utility power generation is significant and growing. Non-utility capacity is about 73,000 megawatts (approximately 10% of utility power generation capacity) and net generation (sales) was 383 billion kWh (approximately 12% of utility net generation). Unless noted, the data used in this study is from the EIA utility industry database published on EIA's web pages.

Coal-Fired Power Generation

An underlying assumption of the market study is that HIPPS will be most likely to enter and build a market in areas of the country where coal is already in wide use. EIA data is presented in Exhibit 6-2 for 17 States where coal is important to present and likely future power generation.

Exhibit 6-2
State Coal Consumption and Power Generation

EIA Data for 1997			
		Coal-Fired Generation 10^9 kWh	Coal Use 10^6 Tons
1	Texas	135.7	96.5
2	Ohio	124.9	52.9
3	Indiana	108.9	54.8
4	Pennsylvania	105.5	42.6
5	Kentucky	87.9	38.3
6	West Virginia	87.7	34.5
7	Illinois	76.1	41.0
8	Alabama	71.6	30.8
9	North Carolina	70.2	27.2
10	Georgia	66.2	30.6
11	Florida	66.0	27.4
12	Michigan	65.6	31.9
13	Missouri	59.9	35.2
14	Tennessee	58.9	24.5
15	Wisconsin	40.8	23.6
16	Utah	32.1	14.3
17	New Mexico	27.1	15.8

On Exhibit 6-2, the first 15 States are ordered by the amount coal-fired generation. The last two States, Utah and New Mexico are listed to represent Western U. S. bituminous coals in States where coal-fired power production is significant.

Aging Power Generation Units

Another potential criteria for influencing the HIPPS greenfield and repowering markets is the age of existing coal units that might be replaced by HIPPS (Exhibit 6-3). Clearly, not all units will be replaced as they age, nor can all the units that are replaced use the HIPPS technology. Additionally, the "retirement age" varies widely among coal-fired units.

Exhibit 6-3
Aging of Utility Coal-Fired Units for 17 States

	1997 EIA Data	Number of Units	Average Age years	Average Capacity MW	Oldest Unit	Total MW of Units 1960 and Earlier	Newest Unit
1	Texas	36	17	576	1971	0	1992
2	Ohio	99	35	240	1933	5,994	1991
3	Indiana	78	34	265	1925	3,804	1995
4	Pennsylvania	50	37	374	1948	4,019	1980
5	Kentucky	58	32	278	1950	2,427	1990
6	West Virginia	33	36	453	1943	2,859	1980
7	Illinois	41	34	257	1948	2,376	1982
8	Alabama	39	37	323	1908	3,768	1991
9	North Carolina	45	40	278	1940	3,085	1983
10	Georgia	38	35	381	1941	1,505	1989
11	Florida	31	25	380	1953	621	1996*
12	Michigan	48	35	257	1943	3,066	1985
13	Missouri	43	33	261	1948	1,091	1986
14	Tennessee	33	41	293	1951	6,105	1973
15	Wisconsin	48	40	141	1935	1,645	1985
16	Utah	9	23	451	1954	189	1987
17	New Mexico	10	26	428	1963	0	1984
	Total/Average	739	31	313	---	44,514	---

** One of the two units starting operation in 1996 is a integrated gasification combined cycle plant (Tampa Electric s Polk Plant)*

The data shown in Exhibit 6-3 are augmented in Appendix 6-A wherein coal-fired capacity by state and first year operation are displayed. The graphs illustrate the number and size (name plate capacity) of units and their ages. In general, many of the oldest units are relatively small and the biggest units have been more recently built. It is clear from the data in the last column that utility construction of new coal-fired units has not been extensive in the last 10 years.

However, there are some signs of improved market conditions for coal-fired units if they are clean and economical. Tractebel Energy of Houston, Texas recently announced[*] the start of construction of a 440 MW facility using two circulating fluid bed boilers. The facility is near Chester, Mississippi. Southern Indiana Gas & Electric Company of Evansville, Indiana is reported as purchasing a 100 MW CFB for a new plant near Mount Vernon, Indiana. These units

[*] Power, November/December 1998, page 4.

were not shown in the EIA utility data, and their construction holds promise for a larger coal-fired power generation market than can be inferred only from EIA data.

Electric Power Generation Growth

Growing markets, where the demand for power generating capacity is increasing, are likely to be attractive for HIPPS to gain a market position. A caveat for the growth criteria is that historical growth may not reflect future plans, and indeed, the past growth may satisfy demand for the future, and thus be a reason to exclude HIPPS or other generating capacity additions.

Exhibit 6-4 illustrates generation growth by presenting the average annual increase/decrease for coal and natural gas used by utilities for power generation. The fuel data was used rather than generation data to examine how coal and natural gas are changing in relation to each other for power generation.

Exhibit 6-4
Average Annual Change of Utility Fuel Consumption

	EIA Data for Years 1993 Through 1997	Coal	Natural Gas
1	Texas	0.9%	-0.3%
2	Ohio	0.5%	2.9%
3	Indiana	2.2%	-5.5%
4	Pennsylvania	1.5%	-1.6%
5	Kentucky	1.6%	15.5% *
6	West Virginia	3.9%	-30.0% *
7	Illinois	4.5%	12.8%
8	Alabama	2.1%	10.0%
9	North Carolina	3.1%	6.7%
10	Georgia	3.5%	11.8%
11	Florida	1.7%	8.3%
12	Michigan	2.0%	8.6%
13	Missouri	7.5%	6.7%
14	Tennessee	0.5%	-5.0% *
15	Wisconsin	3.8%	16.2%
16	Utah	0.4%	-9.3%
17	New Mexico	1.1%	3.2%

In Exhibit 6-4, the average annual changes are simple calculations of the average for a 5 year period, 1993 – 1997. Other calculations were examined to avoid misleading results that could be caused by highly variable yearly numbers. The simple average i.e.

(Consumption Year 5 – Consumption Year 1) / Consumption Year 5/5

provided results consistent with the data and the other calculating options.

Utilities in the three States marked with * consumed less than 3,000 million cubic feet of natural gas in 1997, and the percentage changes may not reflect a "real" trend, as small absolute changes can lead to large percentage changes.

Fuel Price Changes

A HIPPS market is expected to strongly influenced by the relative prices for coal and natural gas. Coal is the main fuel for HIPPS; natural gas is the fuel for HIPPS' main competitor in today's market – gas turbine combined cycle power plants. Exhibit 6-5 shows the average annual changes for coal and gas in the 17 States for the years 1993 through 1997.

Exhibit 6-5
Average Annual Change of Utility Fuel Prices

	EIA Data for Years 1993 Through 1997	Coal	Natural Gas
1	Texas	-2.4%	1.6%
2	Ohio	-1.7%	4.2%
3	Indiana	-2.0%	2.8% *
4	Pennsylvania	-1.5%	2.5%
5	Kentucky	-2.6%	2.2% *
6	West Virginia	-3.1%	-6.0% *
7	Illinois	-3.2%	0.5%
8	Alabama	-3.9%	1.5%
9	North Carolina	-4.0%	-2.5%
10	Georgia	-3.2%	-4.3%
11	Florida	-0.8%	1.2%
12	Michigan	-2.9%	-3.3%
13	Missouri	-9.0%	3.3%
14	Tennessee	-3.2%	14.4% *
15	Wisconsin	-2.5%	3.2%
16	Utah	-1.7%	-2.1%
17	New Mexico	-0.3%	3.1%

As for the previous data exhibit, a simple 5 year average change appears to fairly represent the data and show how fuel prices have increased or decreased in the States during that time.

States marked with * consumed relatively little natural gas, and the average change may be affected by variations in the small amounts.

Electricity Prices

The costs of electricity have been estimated for HIPPS and other generation technologies. The price of electricity is shown in Exhibit 6-6 for the 17 States. The exhibit data reflects utility revenues from all sectors of consumers, and includes generation from all energy sources –fossil, nuclear, renewables. Costs comparable to the HIPPS cost of electricity are not part of the EIA database.

Exhibit 6-6
Average State Electricity Price

	EIA Data for 1997	Cents per kWh	Comparison Ratio*
1	Texas	6.17	1.01
2	Ohio	6.25	1.03
3	Indiana	5.29	0.87
4	Pennsylvania	7.99	1.31
5	Kentucky	4.03	0.66
6	West Virginia	5.02	0.82
7	Illinois	7.71	1.27
8	Alabama	5.33	0.88
9	North Carolina	6.48	1.06
10	Georgia	6.37	1.05
11	Florida	7.19	1.18
12	Michigan	7.04	1.16
13	Missouri	6.09	1.00
14	Tennessee	5.31	0.87
15	Wisconsin	5.22	0.86
16	Utah	5.17	0.85
17	New Mexico	6.80	1.12

* *The ratio of each State s electricity price to the average price of 17 States.*

For HIPPS to compete in a State, its COE should be substantially less than the prices above, as they include transmission and distribution, overhead and profit and other items included with the price of electricity to the ultimate consumer. The commercial 300 MW conceptual HIPPS design's COE ranges from 3 to 5 cents per kWh, based on present value calculations over a range of fuel costs and financial criteria.

Utility Planned Capacity Additions.

Exhibit 6-7 shows EIA data for the U. S. for additions of capacity over the years 1997 through 2006, and is presented to illustrate the overall planning by utilities for the near term future. As is clear, the largest planned additions are to be natural gas-fired units, some 32,000 out of the 42,000 megawatts total. Thus, in addition to the planned coal-fired additions, and changes to units discussed later, there is a large HIPPS market opportunity if some of the utilities planning to build gas-fired units can be convinced that HIPPS is a better business and economic choice.

Exhibit 6-7
Planned Additions by Utilities

EIA Data for Utilities --1997 through 2006	Existing Number of Units	Nameplate Capacity MW	Number of Units to be Added	Nameplate Capacity MW
U.S. Total......................	10,422	756,484	370	42,079
Coal.......................	. 1,214	326,457	11	4,924
Petroleum.............	. 3,282	77,683	40	2,146
Gas........................	. 2,205	145,639	231	32,000
Water (Pumped Storage Hydroelectric)........	. 140	18,387	1	204
Water (Conventional Hydroelectric)........	. 3,340	72,566	64	767
Nuclear...................	. 110	108,976	--	--
Waste Heat..............	. 55	4,548	13	1,941
Other Renewable2/..........	. 76	2,228	10	97

Exhibit 6-8 reports the data for coal and natural gas additions to utility plants in the 17 States being examined. Consistent with the National data, the natural gas plant additions far outweigh the coal additions. Further, the six additions planned for Texas are likely to use lignite or other low rank coals, and because of the typical low ash fusion temperatures of these coals, they are less than optimum fuels for HIPPS installations. Again, it appears that for the HIPPS market to have a significant impact on power generation, some of the utilities planning to increase gas-fired capacity need to be convinced that coal-fired HIPPS is more attractive.

Exhibit 6-8
Planned Coal and Gas Additions by Utilities

EIA Data for Utilities --1997 through 2006		Coal		Natural Gas	
		Number of Units to be Added	Nameplate Capacity MW	Number of Units to be Added	Nameplate Capacity MW
1	Texas	6	4,151	21	2,413
2	Ohio	--	--	5	383
3	Indiana	--	--	23	3,406
4	Pennsylvania	--	--	5	602
5	Kentucky	--	--	8	1,007
6	West Virginia	--	--	--	--
7	Illinois	--	--	16	2,704
8	Alabama	--	--	5	554
9	North Carolina	--	--	12	3,041
10	Georgia	--	--	10	2,074
11	Florida	1	157	15	2,934
12	Michigan	--	--	--	--
13	Missouri	--	--	12	1,734
14	Tennessee	--	--	--	--
15	Wisconsin	1	60	13	1,190
16	Utah	--	--	--	--
17	New Mexico	1	233	1	103
	Totals	9	4,601	146	22,145

Utility Planned Changes

EIA also reports the changes that are planned by utilities for ten year periods. The information on coal-fired units and the 17 States is summarized below in Exhibit 6-9. The changes indicated on the exhibit include retirements, decreases and increases in capacity and reactivation of units. No repowering of coal-fired units is planned by utilities in these 17 States.

Exhibit 6-9
Planned Changes by Utilities

EIA Data for Utilities -- 1997 through 2006		Number of Units to be Changed	Nameplate Capacity MW
1	Texas	1	600
2	Ohio	2	888
3	Indiana	8	809
4	Pennsylvania	6	610
5	Kentucky	4	1,436
6	West Virginia	2	1,140
7	Illinois	--	--
8	Alabama	1	125
9	North Carolina	--	--
10	Georgia	--	--
11	Florida	--	--
12	Michigan	4	583
13	Missouri	--	--
14	Tennessee	--	--
15	Wisconsin	1	30
16	Utah	--	--
17	New Mexico	--	--
		29	6,221

The only coal-fired units listed in the EIA data for repowering are in the State of Delaware: Two 80 MW units at the Indian River (Sussex) Station of Delmarva Power and Light Company. The Delmarva repowering is planned for 2001 (unit 2) and 2003 (unit 1).

Exhibit 6-10 shows some of the details for planned changes to the coal-fired units.

Exhibit 6-10
Details for the Planned Changes by Utilities

EIA Data for Utilities --1997 through 2006

State, Utility, Station(s)	Unit Number	Name Plate Capacity MW	Type of Planned Change	Year for Planned Change
Texas	1	600		
Central Power & Light Co.				
Coleto Creek (Goliad)	1	600	D	1997
Ohio	2	888		
Columbus Southern Power Co.				
Conesville (Coshocton)	5	444	A	1997
Conesville (Coshocton)	6	444	A	1997
Indiana	8	809		
PSI Energy Inc.				
Edwardsport (Knox)	7	40.3	RT	2004
Edwardsport (Knox)	8	69	RT	2004
Noblesville (Hamilton)	1	50	RT	2006
Noblesville (Hamilton)	2	50	RT	2006
R Gallagher (Floyd)	1	150	D	2003
R Gallagher (Floyd)	2	150	D	2003
R Gallagher (Floyd)	3	150	D	2003
R Gallagher (Floyd)	4	150	D	2003
Pennsylvania	6	610		
Duquesne Light Co.				
F R Phillips (Allegheny)	1	69	RA	1999
F R Phillips (Allegheny)	2	81.3	RA	1999
F R Phillips (Allegheny)	3	81.3	RA	1999
F R Phillips (Allegheny)	4	179.7	RA	1999
Pennsylvania Electric Co.				
Seward (Indiana)	5	156.2	RT	2001
Warren (Warren)	1	42.3	RT	2000
Kentucky	4	1,436		
East Kentucky Power Coop Inc.				
Dale (Clark)	3	66	A	1997
H L Spurlock (Mason)	1	305.2	A	1997
H L Spurlock (Mason)	2	508.3	D	2000
Kentucky Utilities Co.				
Ghent (Carroll)	2	556.4	D	2000
West Virginia	2	1,140		
Virginia Electric & Power Co.				
Mt Storm (Grant)	1	570.2	D	2005
Mt Storm (Grant)	2	570.2	D	2004

State, Utility, Station(s)	Unit Number	Name Plate Capacity MW	Type of Planned Change	Year for Planned Change
Alabama	1	125		
Alabama Power Co.				
Gorgas (Walker)	6	125	RT	2006
Michigan	4	583		
Consumers Power Co.				
B C Cobb (Muskegon)	4	156.3	A	1999
B C Cobb (Muskegon)	5	156.3	D	1997
Detroit Edison Co.				
Conners Creek (Wayne)	15	135	RA	2000
Conners Creek (Wayne)	16	135	RA	2000
Wisconsin	1	30		
Wisconsin Public Service Corp.				
Pulliam (Brown, subbituminous)	4	30	RT	1999

RT = Retire
RA = Reactivate
A = Add capacity
D = Decrease capacity

HIPPS Market Assessment

While the EIA data used in the preceding sections is valuable and interesting, it does not by itself say anything about a market for HIPPS technology, because potential HIPPS users are unaware of the HIPPS costs and performance. The costs and performance of HIPPS, while still uncertain and under development, are another part of the market study, and values estimated in Phase I and revised in Task 1.3 of Phase II will be used in following sections forecast a market for HIPPS.

The market assessment portion of the study seeks answers to the following major issues.

- What are the markets for HIPPS plants?
- How large might the HIPPS market become?
- What is the timeframe for a HIPPS market?
- Where are the best HIPPS opportunities?
- What are the competitors to HIPPS in the power generation market? And, how does HIPPS compare to the competition?

Future Markets

The HIPPS technology is well suited to both new plant and repowering applications. For repowering cases, HIPPS would be most attractive where added capacity (generation capacity greater than from the existing steam turbine generator) is desired.

The HIPPS plants will operate mostly in base-load for several reasons. There will be a desire to operate the high temperature furnace with few start-and-stop cycles. Since HIPPS will be one of the most efficient and low cost plants in a generation system, the economic dispatch will indicate a high usage. However, with the combination of a gas turbine and conventional steam system, HIPPS will be more flexible than a typical base-load plant such as a pulverized coal plant for example, the gas turbine and part of the steam turbine generator system could run solely on natural gas.

The technology and the current power generation market indicate that HIPPS units will be moderate in size, say 100 to 300 megawatts. However, HIPPS is well suited for use as a modular component of a phased construction scheme, and could be used for much larger plants. If properly planned and executed, major economies of scale are possible in a large phased construction plant. For example, a single flue gas desulfurization system could be used for several HIPPS modules, or the gas turbines could be operated while the coal portion of the plant is being installed.

For the foreseeable future, HIPPS plants will be fueled with a combination of coal and natural gas. The all-coal HIPPS requires special materials development and engineering solutions to a number of problems before the all coal case is feasible. Thus, the plant location should be sufficiently large for coal storage facilities and possibly ash disposal, and systems for supplying coal and gas should be reasonably near the plant site.

HIPPS is designed to operate as a good friend to the local community and the environment. The design criteria is 1/10 of the current emission limits for new coal plants. Systems to perform that level of control are included with the price and efficiency estimates for HIPPS. The high efficiency reduces greenhouse gas emissions compared to other coal-based systems. Environmental cleanliness is one of the strong points for marketing HIPPS.

The HIPPS technology can be used in the U. S. and most other parts of the world. There are no special, high-tech equipments that need special operation and maintenance or training. HIPPS looks and operates very much like a conventional power plant. As long as the estimates for performance and economics hold true as the technology develops, a wide range of owners will want to use HIPPS. Utilities, independent producers, merchant plants and others will consider HIPPS for cases where coal is available and other conditions are favorable to adding electric power generation.

Future Market Size

One estimate of the potential market's limits can be done by examining EIA's estimates[†] for 1996 to 2020 where some 403,000 megawatts or about 1,300 new plants (assuming an average capacity of 300 MW) will be needed in response to growth and replacement of retired plants. EIA also assumes that plants with operating and maintenance cost above 4 cents per kWh will be retired in the next decade. The retirements include 73,000 megawatts of fossil generation. This estimate for new plants is in addition to repowering and life extensions or other actions that power generators may take to reduce the need for new plants.

Almost 50% of the additions will be required in the 2010 to 2020 time because of planned nuclear plant retirements. The EIA forecast is that 85% of the new power will be from gas

[†] Annual Energy Outlook 1998, with Projections to 2020; December, 1997. All values are from the EIA reference case.

turbines and gas turbine combined cycle plants. Only 49,000 megawatts of new coal-fired capacity is forecast, and 58 percent of that generation will come online in the 2010 to 2020 time.

Thus for the new plants, the bottom of the HIPPS market is some portion of the 49,000 megawatts of coal-fired additions. Using 20 percent as an estimate of the portion of the total market available for HIPPS, that would mean that some 10,000 megawatts of capacity could be built, mostly in the 2010 to 2020 time period. If for example, 8,000 megawatts is built in that 10 year period, it would mean about 2 to 3 HIPPS plants would have to be installed each year (assuming an average capacity of 300 MW). Even at such a conservative estimate, HIPPS would seem to be a good business venture, and the timing is about right for industry to demonstrate and accept the technical and economic attributes of the technology. Given earlier HIPPS plant estimates of slightly less than $800 per kW, total installed cost, the 8,000 megawatts would equal costs for a buyer, or revenues to a seller of $6.4 billion (1998 dollars).

The HIPPS market could expend significantly if the technology is able to replace some of the new capacity planned for gas turbine combined cycle plants, which is about 354,000 megawatts. Even winning 5% or 10% of this capacity would more than double or triple the installation of new HIPPS plants, and based on cost of electricity estimates, HIPPS should be very competitive with gas turbine combined cycle for a number of scenarios.

In the nearer term, from the present to 2006, the potential market for replacements of existing coal plants is smaller. Exhibits 6-8 and 9 illustrate this, showing only 9,200 megawatts of additions and 12,440 megawatts of change over the 10 year period. However, if HIPPS is technically ready and economically proven for this timeframe, there are also about 44,000 megawatts of gas-fired capacity additions that would be open to competition by a clean, economical HIPPS system.

Other technologies may also win portions of the demand for new capacity: Distributed power generation, using a number different generators – fuel cells, microturbines, diesel and gas engines, may have a significant role in future power generation. For one example, Allied Signal has commitments for 3,000 microturbine generator units in 1999 and 10,000 units in 2000[‡]. Each unit produces only 75 kW of power and their widespread use requires solutions of a number of issues, but they are part of the overall competition that makes any forecast of markets difficult and out-of-date relatively quickly if not periodically updated.

The repowering market, and the role of HIPPS in that market are more difficult to define. EIA data[§] shows only about 2,000 megawatts of capacity planned for repowering or life extension for the 1996 to 2006 period, and very few coal units are included in the estimate. There may be more repowering and upgrading work planned by non-utility generators, but no data was found to define this. EIA did report that non-utility generators planned to add 4,000 megawatts of capacity in the years 1997 to 1999. For comparison, non-utility generating capacity in 1996 was about 73,000 megawatts.

[‡] T&D Electric World, December 1998 Volume 212; A publication of the McGraw-Hill Companies.

[§] EIA Inventory of Power Plants in the United States – As of January 1, 1997.

Another target for repowering could be a portion of the 73,000 megawatts of fossil-steam (coal, oil and gas) capacity scheduled for retirement over the 1996 to 2020 period. However, each plant would require site specific analysis to evaluate that possibility.

In summary, for the repowering market, because of the variability of site and unit specific conditions it is difficult to estimate a future market. However, while it appears that the repowering market will be relatively small, it could be an important one for HIPPS to gain a foothold in the generation business. Even if just one of the plants planned for repowering or life extension in the next ten years were to use the HIPPS technology, that would benefit the future market. Over the longer term, to 2020, more repowering opportunities for HIPPS are likely. However, it is noted that adding repowered capacity is likely to replace or substitute for new plant capacity described in earlier paragraphs.

One conclusion that can be fairly drawn is that the combined new plant and repowering market for HIPPS, which as reasoned above is to be conservatively on the order of $6 to 7 billion in the 2010 to 2020 period, should be large enough to attract business interest. Other market factors are examined next, but purely from the size of a potential market, HIPPS is worth pursuing.

Future Market Timing

As reported above, the EIA forecasts a major need for additional capacity in the 2010 to 2020 period, largely because of planned nuclear plant retirements. HIPPS technology should be available to meet part of the requirement.

As with all developing technologies, schedules depend on many internal and external factors, but the sequence and milestones below reasonably estimate HIPPS progress.

- Engineer, install and test a near commercial scale HIPPS system by the end of year 2003.
- Install the first commercial unit using tax incentives or other subsidies by 2006.
- Install first unsubsidized system by 2008.
- Beyond this, the rest of the success for HIPPS will depend on its performance and changing conditions in the industry: gas turbine and other technological advances; fuel prices; electric power supply and demand; and numerous others.

If HIPPS can develop and become commercial by approximately 2008, the technology would be sufficiently tested in commercial conditions to be deployed on as large as scale as made feasible by the demand for electric power and competing generation systems.

While the present discussion is limited to U.S. markets, the foreign market may have large impacts of the size and time table for commercializing HIPPS. As the technology advances, its applications outside of the U.S. should be more closely examined.

Future Market Locations

For the United States, there are significant data from which one may estimate and forecast markets for HIPPS technology. However, it needs to be continuously remembered that such forecasts are only the best guesses of the forecaster, and they are more useful in comparing technologies or marketing opportunities than for the absolute values: A market study is only one part of the decision making process that may lead to a market plan followed by eventual manufacturing and sales of the products.

Forecasting location(s) for a market is a section of the market study that would benefit the most from person-to-person communications to discuss plans for future power plants. However, the study's scope is limited to examining available data. A summary of the data is shown on Exhibit 6-11, the methodology is explained below.

To forecast the locations for future HIPPS plants, the exhibit was used as follows to estimate which States might offer the best opportunity for HIPPS plants. First, any State that had a planned coal unit addition received a "boxed" value in that column. Next, the three largest values for each column are highlighted with boxes. (The second column, Utility Consumption, is not used in the selection.) For example in the two growth rate columns, the coal and natural gas rates are combined to select three States with the largest values. For price growth, a negative coal price rate increase was considered favorable when combined with a positive gas price rate increase, so for Ohio, -2.4 and 1.6 total to one of the high values as 4.0. Missouri and Tennessee have even wider spreads and received boxes.

Finally, those States with two boxed values (Ohio, for example, has a high price growth rate and a high count of MW built before 1960.) are themselves boxed in the first column: Ohio, Indiana, Pennsylvania, Illinois are major coal producers and users; less obvious without the data, Missouri, Tennessee and Wisconsin also have two boxed values and may be high potential places to market the HIPPS technology.

Exhibit 6-11
Summary of Data from EIA Sources

		Utility Consumption 1997 Data		Utility Annual Growth Rates 1993-1997		Utility Annual Price Growth 1993-1997		Units to be Added	Capacity MW	Units to be Added	Capacity MW	Units to be Changed	Capacity MW	Total MW of Units 1960 or before.
								EIA Data for 1997 Through 2006						
		Generation 10^9 kWh	Coal Use 10^6 Tons	Coal	Natural Gas	Coal	Natural Gas	Coal		Natural Gas		Coal		Coal
1	Texas	135.7	96.5	0.9%	-0.3%	-2.4%	1.6%	6	4,151	21	2,413	1	600	0
2	Ohio	124.9	52.9	0.5%	2.9%	-1.7%	4.2%	--	--	5	383	2	888	5,994
3	Indiana	108.9	54.8	2.2%	-5.5%	-2.0%	2.8%	--	--	23	3,406	8	809	3,804
4	Pennsylvania	105.5	42.6	1.5%	-1.6%	-1.5%	2.5%	--	--	5	602	6	610	4,019
5	Kentucky	87.9	38.3	1.6%	15.5%	-2.6%	2.2%	--	--	8	1,007	4	1,436	2,427
6	West Virginia	87.7	34.5	3.9%	-30.0%	-3.1%	-6.0%	--	--	--	--	2	1,140	2,859
7	Illinois	76.1	41.0	4.5%	12.8%	-3.2%	0.5%	--	--	16	2,704	--	--	2,376
8	Alabama	71.6	30.8	2.1%	10.0%	-3.9%	1.5%	--	--	5	554	1	125	3,768
9	North Carolina	70.2	27.2	3.1%	6.7%	-4.0%	-2.5%	--	--	12	3,041	--	--	3,085
10	Georgia	66.2	30.6	3.5%	11.8%	-3.2%	-4.3%	--	--	10	2,074	--	--	1,505
11	Florida	66.0	27.4	1.7%	8.3%	-0.8%	1.2%	1	157	15	2,934	--	--	621
12	Michigan	65.6	31.9	2.0%	8.6%	-2.9%	-3.3%	--	--	--	--	4	583	3,066
13	Missouri	59.9	35.2	7.5%	6.7%	-9.0%	3.3%	--	--	12	1,734	--	--	1,091
14	Tennessee	58.9	24.5	0.5%	-5.0%	-3.2%	14.4%	--	--	--	--	--	--	6,105
15	Wisconsin	40.8	23.6	3.8%	16.2%	-2.5%	3.2%	1	60	13	1,190	1	30	1,645
16	Utah	32.1	14.3	0.4%	-9.3%	-1.7%	-2.1%	--	--	--	--	--	--	189
17	New Mexico	27.1	15.8	1.1%	3.2%	-0.3%	3.1%	1	233	1	103	--	--	0

While our market study does not include assessment of foreign opportunities, the first markets for HIPPS may be outside the U. S. In parts of Asia, especially, natural gas and liquefied natural gas are expensive and domestic distribution systems are limited, but coal mining and coal transportation are more developed mature industries. Also, most of the developing countries with coal, gas and oil resources would prefer to sell the gas and oil for dollars, which can be used for imports and investment funding. The demand for energy and environmental improvements is high in Asia and Europe, both of which could benefit from coal-fired HIPPS.

Competitors in the Market

The main competition for HIPPS are plants using gas turbine combined cycle power plant technology, and the future GTCC systems which will be cleaner, more efficient and may cost the same or less than today's GTCC plants. In some special markets, for example where the owner has determined that coal will be used as the primary fuel, HIPPS will be competing against pulverized coal-fired plants, integrated gasification combined cycle and possibly, systems using atmospheric and pressurized fluid bed combustion technologies.

Exhibit 6-12 presents a summary of the investment cost estimating completed in Task 1.3. The HIPPS plant is clearly less expensive than the pulverized coal-fire plant. Published and in-house data was used to estimate the gas turbine combined cycle plant, and $800 per kW was used for a Total Capital Cost, consistent in definition with the other technologies. The three plants are also consistent in capacity and environmental requirements. While the GTCC plant has the lowest capital cost, its fuel is more expensive.

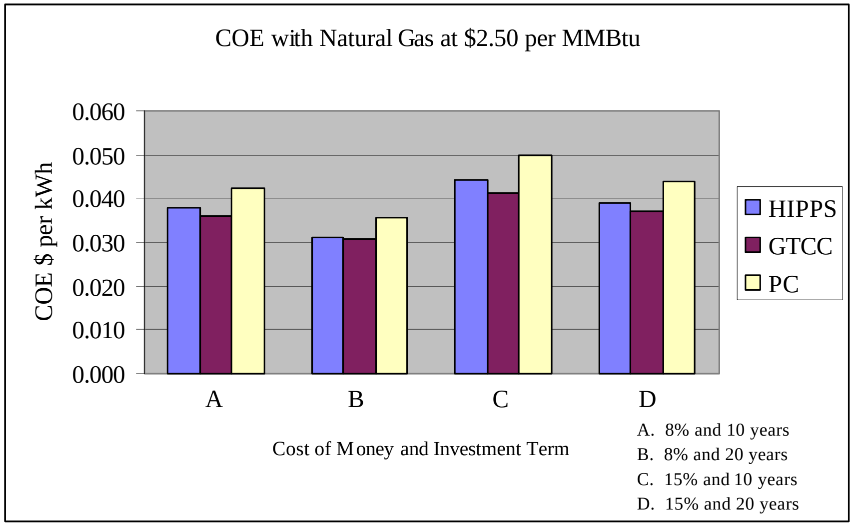
Earlier work did not include an estimate for coal gasification combined cycle, but even the more optimistic estimates for IGCC are some $200 per kW more that the HIPPS and PC plants. The IGCC efficiency is lower than for HIPPS, and to show reasonable economics, the IGCC plant needs to be significantly larger capacity, thus increasing the magnitude of the investment required.

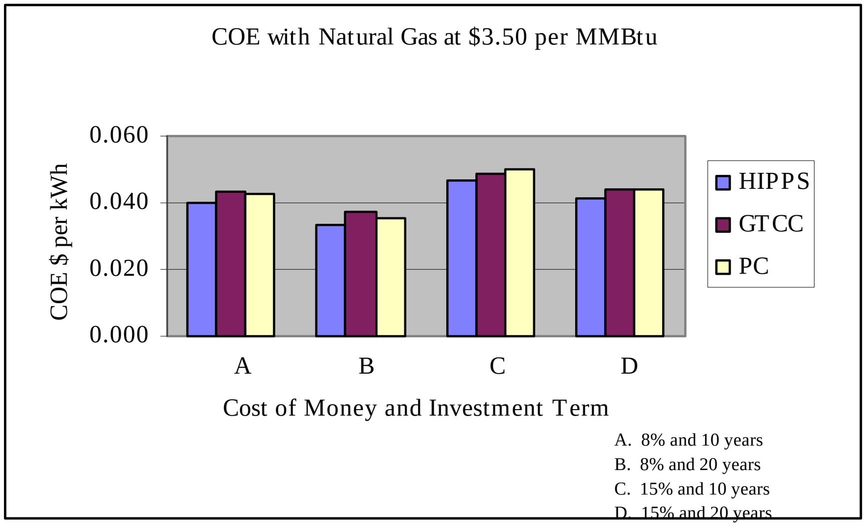
Exhibit 6-12
Cost Estimates from Commercial Plant Conceptual Design and Estimating Task

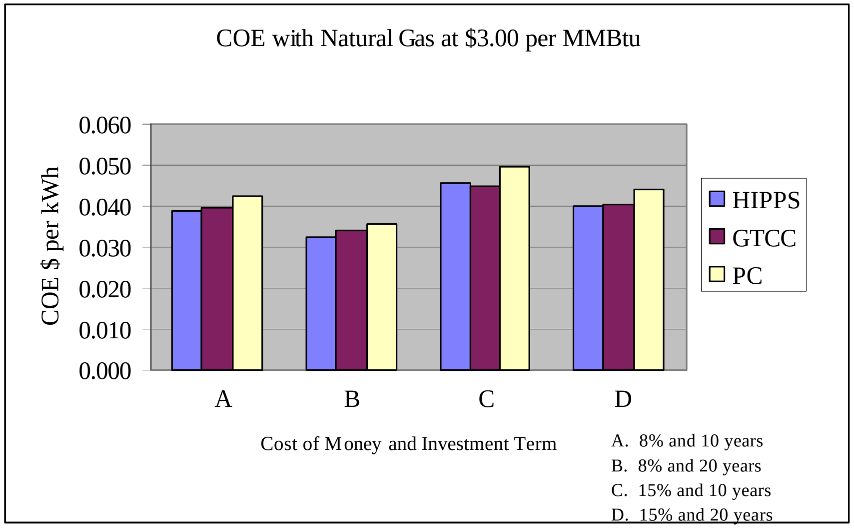
Cost Estimates from Task 1.3.2 for 300 MW Commercial HIPPS Plant Conceptual Design	HIPPS Plant		Pulverized Coal Plant		Gas Turbine Combined Cycle Plant	
	Thousands of 1997 Dollars	$ per kWh	Thousands of 1997 Dollars	$ per kWh	Thousands of 1997 Dollars	$ per kWh
TOTAL CONSTRUCTION COST	238,800	796	258,300	861		
Project Contingency 15 % of TCC	35,820	119	38,745	129		
Total Plant Cost	274,620	915	297,045	990		
Allowance For Funds During Construction 8%	21,970	73	23,764	79		
Total Plant Investment	296,590	989	320,809	1,069		
Owner Costs 5% 0f TPI	14,829	49	16,040	53		
Total Capital Cost	311,419	1,038	336,849	1,123	240,000	800

To account for the differences in fuels and performance, cost of electricity (COE) was calculated for several scenarios as part of the conceptual design and costing task. Exhibit 6-13 presents the results comparing HIPPS, PC and GTCC. The graphs show the results of calculating COE present values for three prices of natural gas, and four sets of cost of money and investment time period criteria (Indicated by A, B, C and D on the graphs.).

Exhibit 6-13
Present Value Costs of Electricity for Different Scenarios







From Exhibit 6-13, the relatively small difference between costs of electricity for HIPPS and GTCC power is clear. While the pulverized coal-fired COE is almost always the highest, the COE for HIPPS and GTCC plants sometimes give the advantage to one, and in other scenarios to the other technology. High natural gas prices favor HIPPS (and even PC plants at the highest price per million Btus); low costs of money and longer investment horizons also favor HIPPS as they reduce the impact of its higher capital costs. Conversely, the higher costs of money and shorter investment periods favor the less capital intense GTCC.

Referring back to Exhibit 6-6, where the reported average electricity prices were give for the 17 States as between $.04 and .08 per kWh, it is not surprising that for the study parameters, the HIPPS and GTCC plants are competitive with existing power generators. Even with reasonable additions to the HIPPS and GTCC COEs for transmission and distribution and profits, the estimated COEs will be less than a number of existing plants' prices for electricity.

Coal was priced at $1.14 per million Btus for the HIPPS conceptual design and estimates. For reference, the average price of natural gas delivered to U. S. utilities in 1997 was $2.76 per million Btus[**].

While the calculations show that HIPPS and GTCC technologies are close competitors, it must be fairly noted that HIPPS is still a developing system, while GTCC plants are in many commercial operations. Both HIPPS and GTCC technologies will continue to advance; increasing efficiencies; reducing emissions and lowering costs of electricity. The selection of HIPPS, once it is commercially available, or GTCC will likely be decided on site, fuel, and plant owner's requirement specifics.

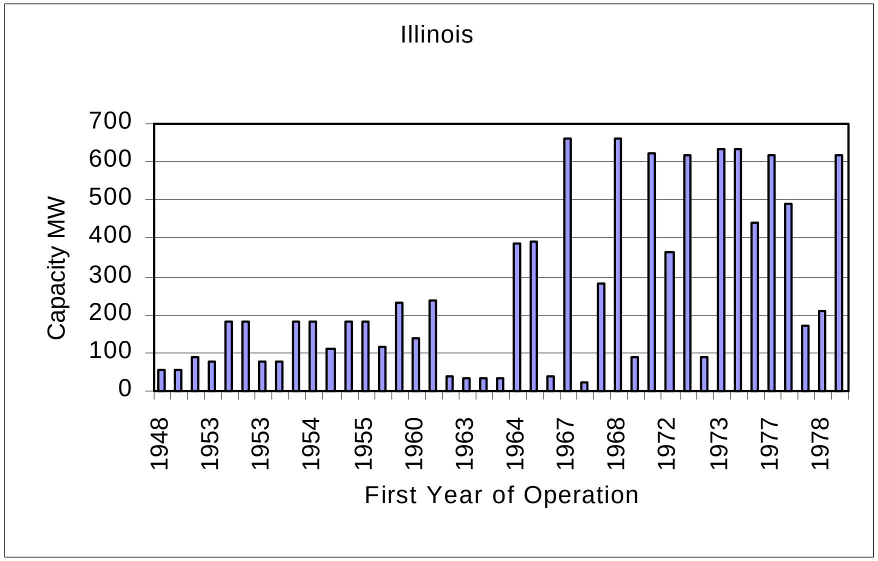
[**] Electric Power Annual 1997 Volume 1 by the EIA.

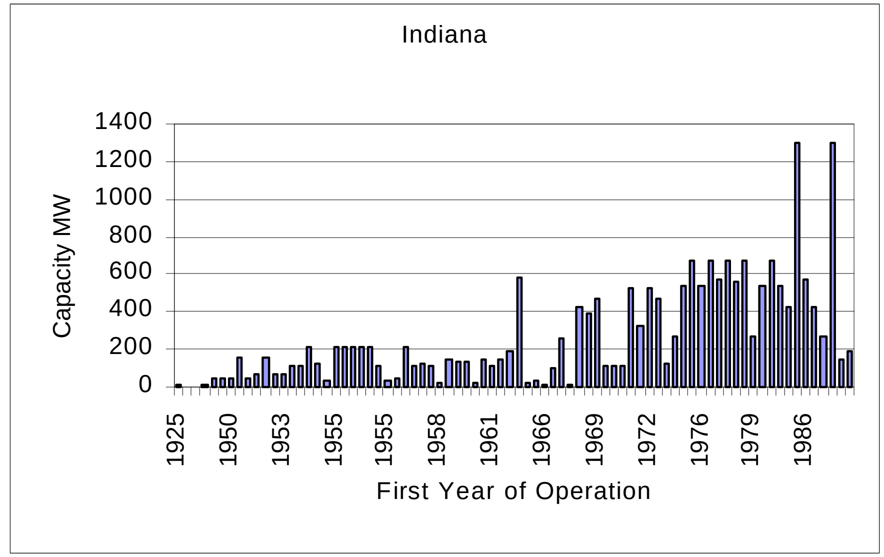
Appendix 6-A

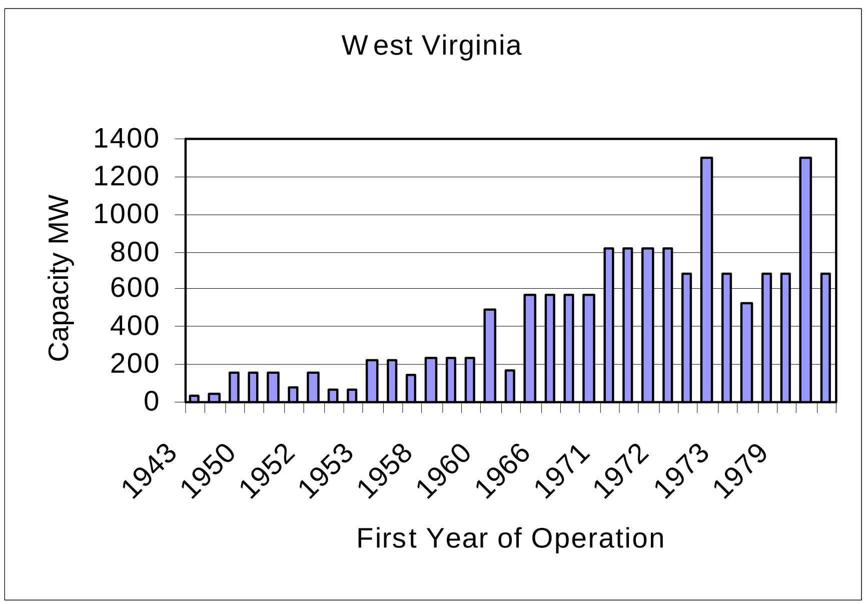
Graphs Showing Coal-Fired Units by State

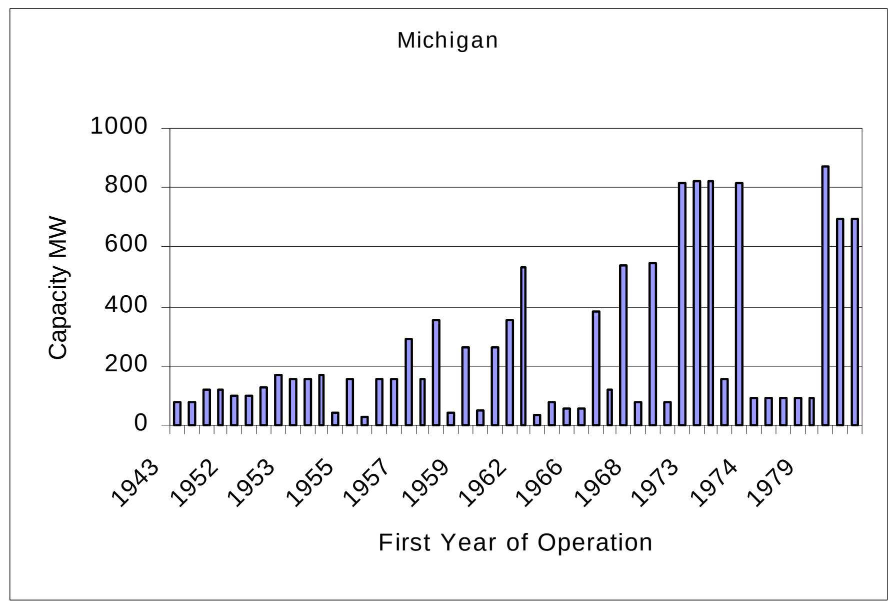
And

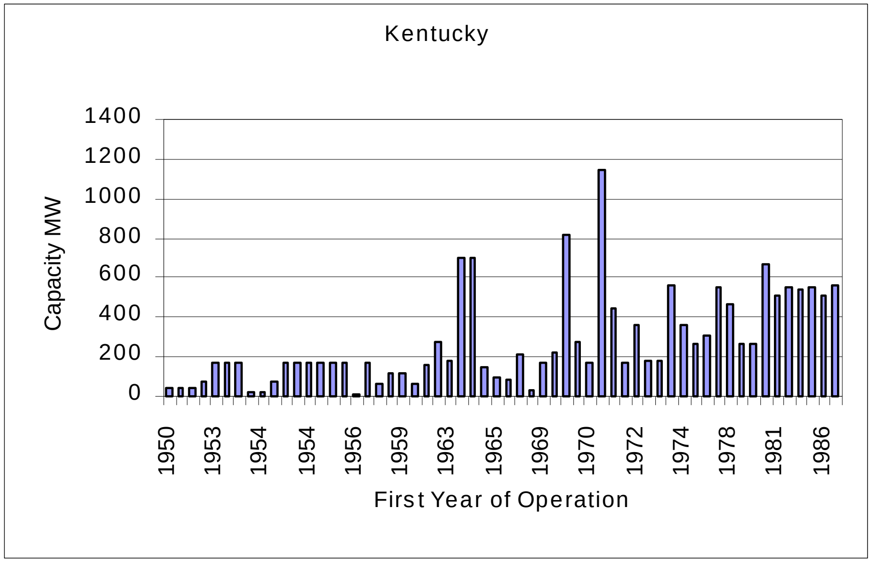
Their First Year of Operation

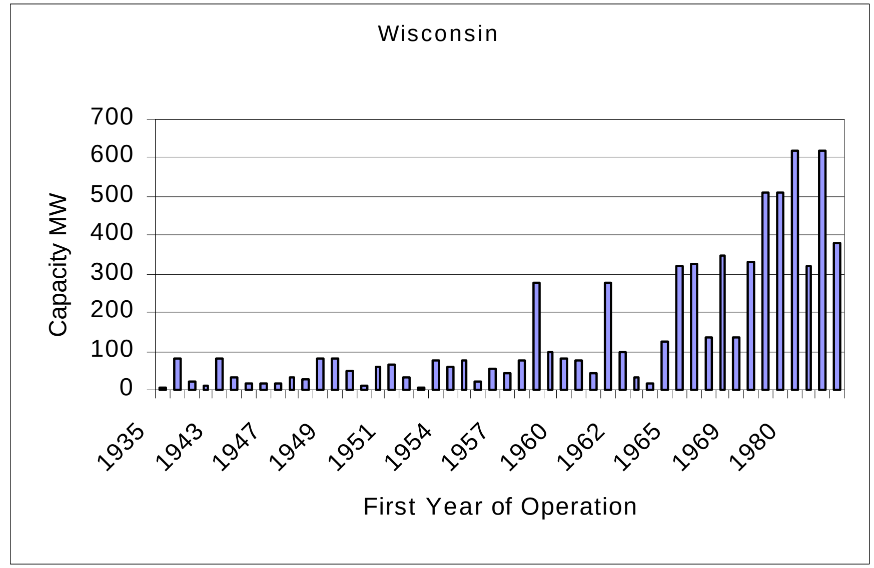

Illinois
Capacity MW
700
600
500
400
300
200
100
0
1948
1953
1953
1954
1955
1960
1963
1964
1967
1968
1972
1973
1977
1978
First Year of Operation

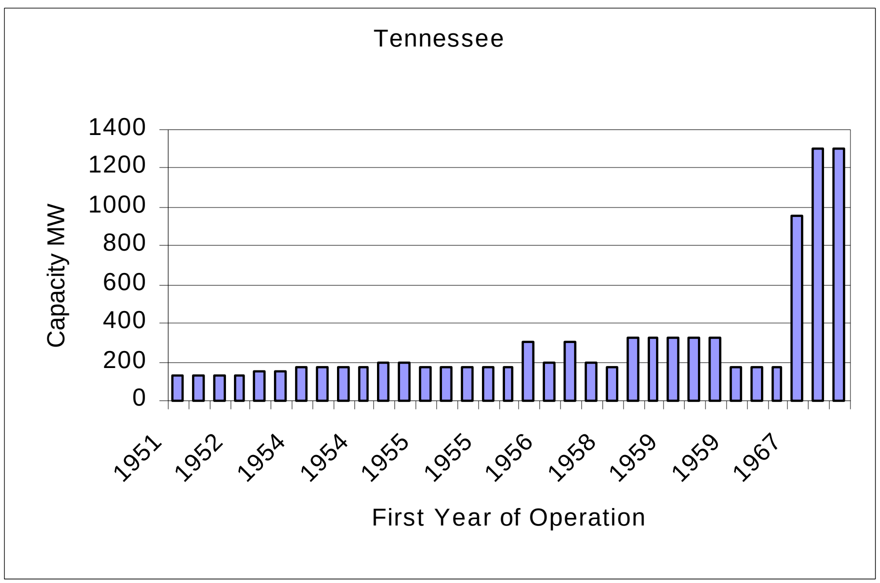

Indiana
Capacity MW
1400
1200
1000
800
600
400
200
0
1925
1950
1953
1955
1955
1958
1961
1966
1969
1972
1976
1979
1986
First Year of Operation

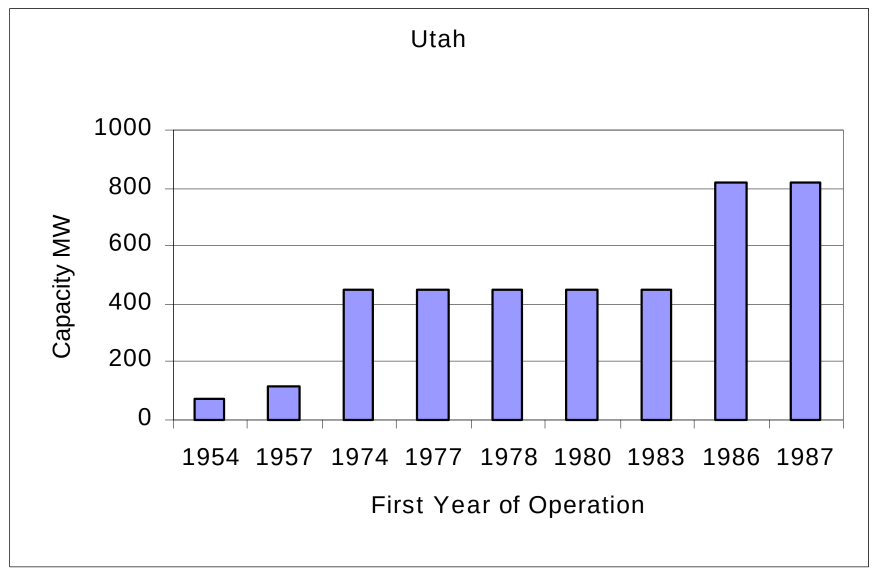

West Virginia
Capacity MW
1400
1200
1000
800
600
400
200
0
1943
1950
1952
1953
1958
1960
1966
1971
1972
1973
1979
First Year of Operation

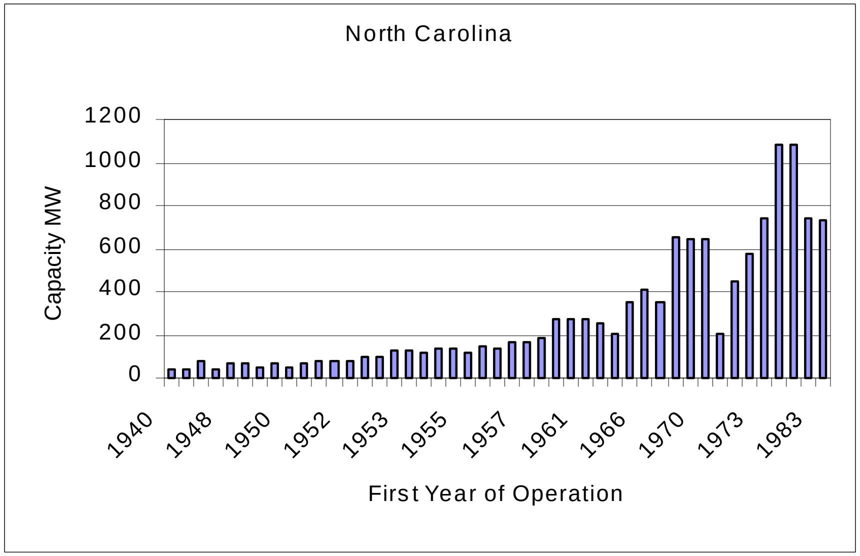

Michigan
Capacity MW
1000
800
600
400
200
0
1943
1952
1953
1955
1957
1959
1962
1966
1968
1973
1974
1979
First Year of Operation

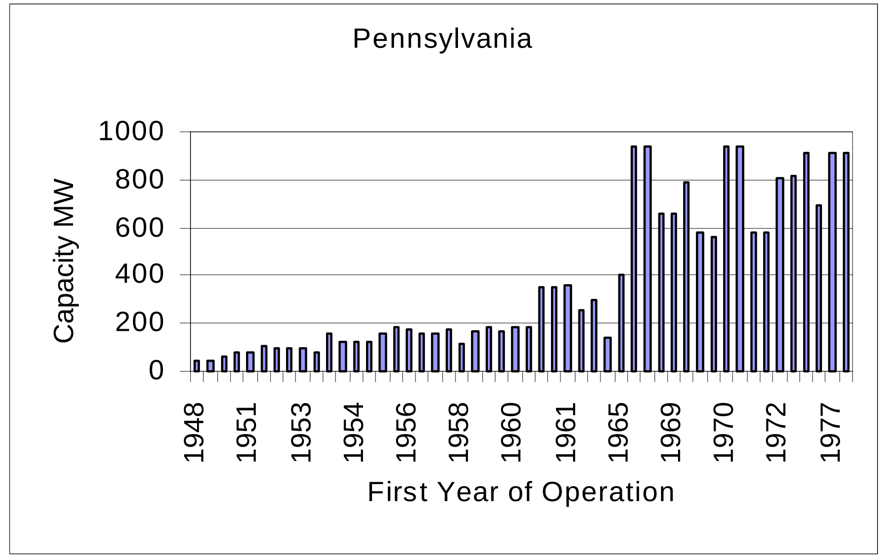

Kentucky
Capacity MW
0
200
400
600
800
1000
1200
1400
1950
1953
1954
1954
1956
1959
1963
1965
1969
1970
1972
1974
1978
1981
1986
First Year of Operation

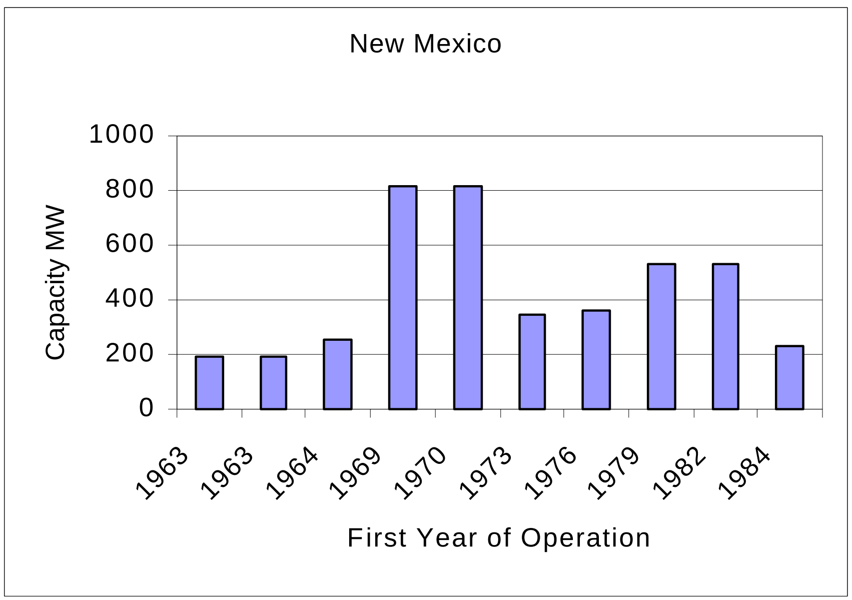

Wisconsin
Capacity MW
0
100
200
300
400
500
600
700
1935
1943
1947
1949
1951
1954
1957
1960
1962
1965
1969
1980
First Year of Operation

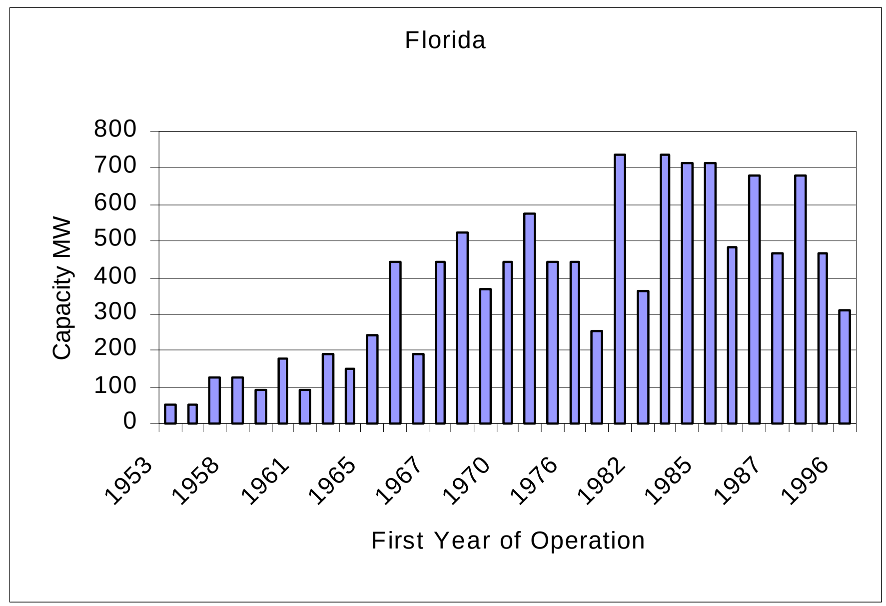

Tennessee
Capacity MW
0
200
400
600
800
1000
1200
1400
1951
1952
1954
1954
1955
1955
1956
1958
1959
1959
1967
First Year of Operation

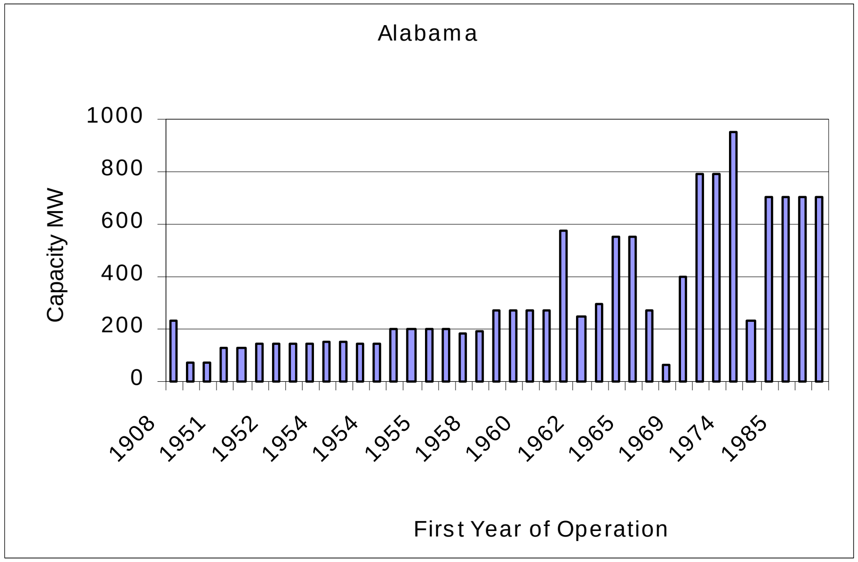

Utah
Capacity MW
0
200
400
600
800
1000
1954
1957
1974
1977
1978
1980
1983
1986
1987
First Year of Operation

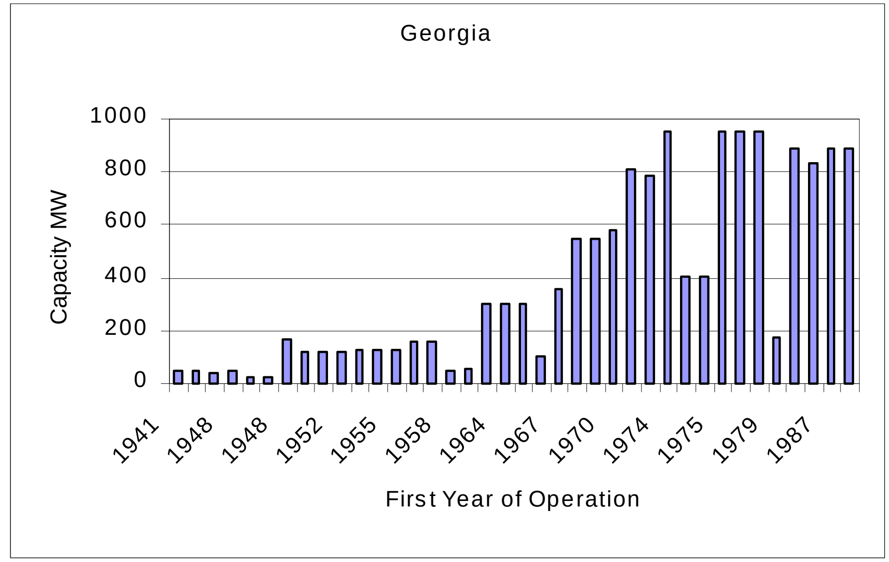

North Carolina
Capacity MW
1200
1000
800
600
400
200
0
1940
1948
1950
1952
1953
1955
1957
1961
1966
1970
1973
1983
First Year of Operation

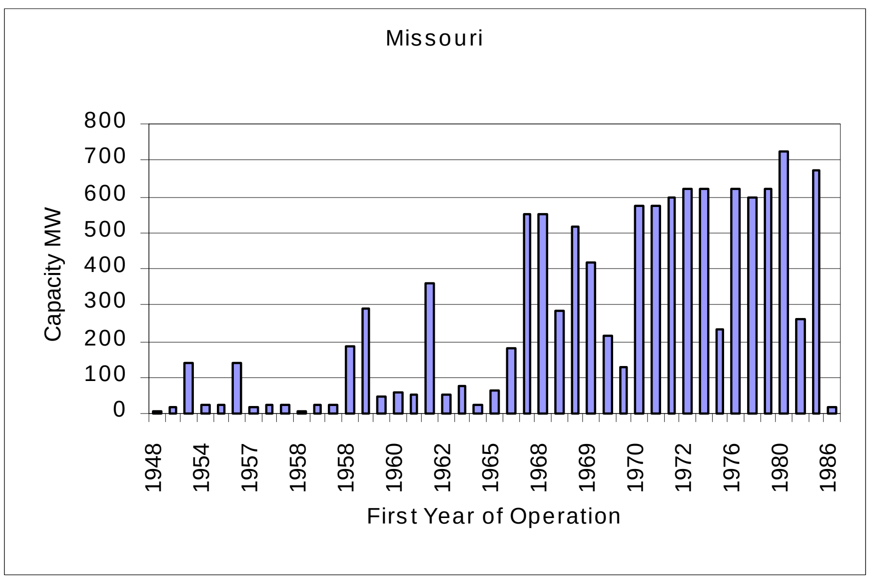

Pennsylvania
Capacity MW
1000
800
600
400
200
0
1948
1951
1953
1954
1956
1958
1960
1961
1965
1969
1970
1972
1977
First Year of Operation

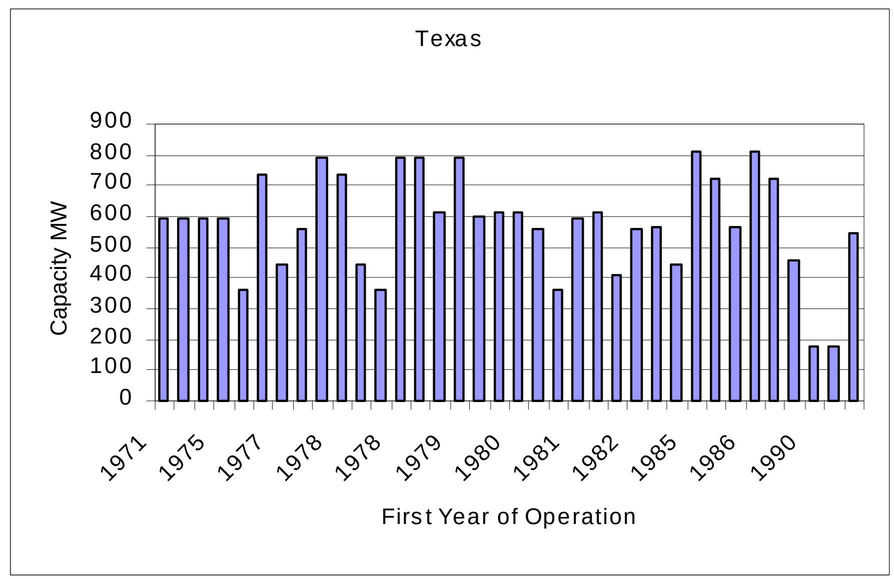

New Mexico
Capacity MW
1000
800
600
400
200
0
1963
1963
1964
1969
1970
1973
1976
1979
1982
1984
First Year of Operation

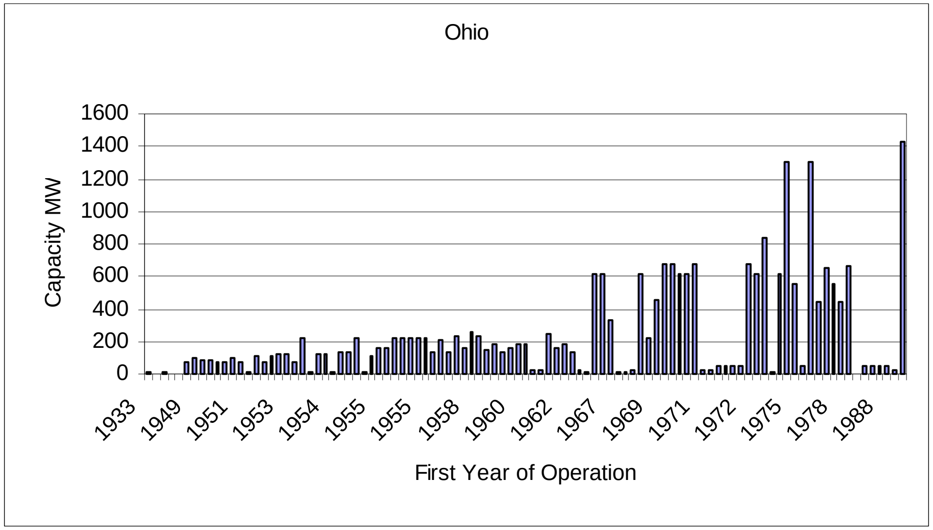

Florida
Capacity MW
800
700
600
500
400
300
200
100
0
1953
1958
1961
1965
1967
1970
1976
1982
1985
1987
1996
First Year of Operation


Alabama
Capacity MW
1000
800
600
400
200
0
1908
1951
1952
1954
1954
1955
1958
1960
1962
1965
1969
1974
1985
First Year of Operation


Georgia
Capacity MW
1000
800
600
400
200
0
1941
1948
1948
1952
1955
1958
1964
1967
1970
1974
1975
1979
1987
First Year of Operation


Missouri
Capacity MW
800
700
600
500
400
300
200
100
0
1948
1954
1957
1958
1958
1960
1962
1965
1968
1969
1970
1972
1976
1980
1986
First Year of Operation


Texas
Capacity MW
900
800
700
600
500
400
300
200
100
0
1971
1975
1977
1978
1978
1979
1980
1981
1982
1985
1986
1990
First Year of Operation


Ohio
Capacity MW
1600
1400
1200
1000
800
600
400
200
0
1933
1949
1951
1953
1954
1955
1955
1958
1960
1962
1967
1969
1971
1972
1975
1978
1988
First Year of Operation