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INNOVATIVE CLEAN COAL TECHNOLOGY

Prepared by:

**Southern Company Services, Inc.
Birmingham, Alabama**

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INNOVATIVE CLEAN COAL TECHNOLOGY (ICCT)

Demonstration of Selective Catalytic Reduction (SCR)
Technology for the Control of Nitrogen Oxide (NO_x)
Emissions from High-Sulfur Coal-Fired Boilers

Quarterly Report No. 2
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Section 1

SUMMARY

The objective of this project is to demonstrate and evaluate commercially available Selective Catalytic Reduction (SCR) catalysts from U. S., Japanese and European catalyst suppliers on a high-sulfur U. S. coal-fired boiler. SCR is a post-combustion nitrogen oxide (NOx) control technology that involves injecting ammonia into the flue gas generated from coal combustion in an electric utility boiler. The flue gas containing ammonia is then passed through a reactor that contains a specialized catalyst. In the presence of the catalyst, the ammonia reacts with NOx to convert it to nitrogen and water vapor.

Although SCR is widely practiced in Japan and Europe, there are numerous technical uncertainties associated with applying SCR to U. S. coals. These uncertainties include:

- (1) potential catalyst deactivation due to poisoning by trace metal species present in U.S. coals that are not present in other fuels.
- (2) performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO₂ and SO₃.
- (3) performance of a wide variety of SCR catalyst compositions, geometries and methods of manufacture under typical high-sulfur coal-fired utility operating conditions.

These uncertainties will be explored by constructing a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas derived from the combustion of high sulfur U. S. coal.

The demonstration will be performed at Gulf Power Company's Plant Crist Unit No. 5 (75 MW capacity) near Pensacola, Florida. The project will be funded by the U. S. Department of Energy (DOE), Southern Company Services, Inc. (SCS on behalf of the entire Southern electric system), and the Electric Power Research Institute (EPRI). SCS is the participant responsible for managing

all aspects of this project.

The project is being conducted in the following three phases:

- Phase I - Permitting, Environmental Monitoring Plan and Preliminary Engineering
- Phase II - Detailed Design Engineering and Construction
- Phase III - Operation, Testing, Disposition and Final Report

During this reporting period, a number of Phase I activities continued. The draft Environmental Monitoring Plan (EMP) prepared by Radian Corporation was reviewed by SCS and Gulf Power. Revisions were incorporated by Radian and the EMP was sent to DOE for review. The EMP included descriptions for the Sampling and Analytical Methods and for the Quality Assurance/Quality Control Project Plan.

SCS decided to eliminate Unit 6 from the project on the basis of discussions with catalyst suppliers, Southern Research Institute's (SRI) duct characterization testing, Dynagen's review of SRI data, and the evaluations by SCS. It was concluded that existing flue gas conditions on Unit 6 prohibit consistent extraction of a representative flue gas slipstream for use in the pilot SCR reactors.

During this reporting period, SCS personnel visited with Haldor Topsoe in Copenhagen, Denmark and Siemens KWU in Erlangen, Germany to a) review SCR catalyst specifications, b) review SCR pilot plant design/operational experience, and c) to tour existing SCR pilot plants and full-scale facilities. As a result of experience gained from the trip, several major revisions to the SCS/DOE SCR pilot plant design were made which have delayed the completion of the Phase I portion of the project. Two major revisions being evaluated include reactor inlet design changes and the addition of an economizer bypass. Additionally, the flue gas/hot air disposition from the pilot plant is being reexamined to alleviate potential cold end temperature problems for the Unit 5 air heater.

During this reporting period, DynaGen, Inc., a fluid mechanics consulting subcontractor, completed flow modeling tests with a 1/9 scale model of Plant Crist's Unit 5 ductwork. Results indicated no significant adverse effects on

flue gas flow profiles downstream of the proposed pilot plant extraction scoop. The reactor inlet modeling effort was initiated and construction of two alternative inlet design models begun. Testing will commence during the first quarter of 1991.

Preparation of the SCR process Design Data Book for use by SCS Design Engineering during detailed design continued. Significant electrical design work was accomplished with the production of single line drawings and a proposed electrical distribution scheme. Previously drafted process flow diagram, ammonia control system, and general arrangement drawings were reviewed and revised, including the new control room location. The Design Data Book will be issued at the conclusion of Phase I which will now likely be during the first quarter of 1991.

Based on the preliminary definition of utility needs from, and interface points with, Plant Crist, a meeting was held with Gulf Power Engineering to review interface issues between the SCR pilot plant and Plant Crist. Interfaces include: electrical, steam, water, air and flue gas systems. Proposed interface points are under review by Gulf.

SCS review of detailed catalyst specifications was completed and supplemental information from each supplier was requested in order to finalize SCR reactor internal design. Evaluation Agreements were signed with Siemens and Haldor Topsoe.

There was a transition in SCS project management for this project as J. D. Maxwell replaced K. W. Bowers as SCS project manager.

Section 2

INTRODUCTION

The Innovative Clean Coal Technology (ICCT) Program is designed to demonstrate clean coal technologies that are capable of retrofitting or repowering existing facilities to achieve significant reduction in sulfur dioxide (SO_2) and/or nitrogen oxides (NO_x) emissions. The technologies selected for demonstration are capable of being commercialized in the 1990s and are expected to be more cost effective than current technologies.

This ICCT project is jointly funded by the U.S. Department of Energy, the Electric Power Research Institute (EPRI), and by Southern Company Services (SCS) on behalf of the entire Southern electric system. The project's objective is to demonstrate the selective catalytic reduction (SCR) process that removes nitrogen oxides (NO_x) from the flue gas of boilers that burn U.S. high-sulfur coal. The SCR technology involves the catalytic reduction of NH_3 , which is injected into the flue gas to react with NO_x contained in the flue gas to produce molecular nitrogen (N_2) and water vapor.

A simplified SCR process flow diagram with major equipment is shown in Figure 1. Specifically, hot flue gas leaving the economizer section of the boiler is ducted to the SCR reactor. Prior to entering the reactor, NH_3 is injected into the flue gas at a sufficient distance upstream of the reactor to provide for complete mixing of the NH_3 and flue gas. The quantity of NH_3 can be adjusted and it reacts with the NO_x from the flue gas. The flue gas leaving the catalytic reactor enters the air preheater where it transfers heat to the incoming combustion air. Provisions are made for ash removal from the bottom of the reactor since some fallout of fly ash is expected. Duct work is also provided to bypass some flue gas around the economizer during periods when the boiler is operating at reduced load. This is done to maintain the temperature of the flue gas entering the catalytic reactor at the proper reaction temperature of about 700°F . The flue gas leaving the air preheater goes to the electrostatic precipitator (ESP) where fly ash is removed. The ESP is part of the existing plant and is generally unaffected by the SCR system except as higher SO_2 content affects the electrical resistivity of the fly ash or if NH_4HSO_4 co-precipitates with the fly ash.

The SCR technology is in commercial use in Japan and western Europe on gas,

FIGURE 1. BLOCK FLOW DIAGRAM OF SCR INSTALLATION.

oil, and on low-sulfur, coal-fired power plants. The first utility applications of SCR catalyst technology started in Japan in 1977 for oil- and gas-fired boilers and subsequently in 1979 for coal-fired boilers. As of 1986, ninety utility boilers in Japan had been equipped with SCR catalyst technology including twenty-two coal-fired boilers. These coal-fired boilers represent a combined capacity in excess of 6500 MWe and are typically fired with a low-ash, low-sulfur coal.

In addition to Japanese experience, several countries in western Europe (most notably West Germany and Austria) have passed stringent NO_x emission regulations that have all but mandated the installation of SCR. Prior to commercial SCR installations in West Germany, utility companies demonstrated several types of SCR facilities in prototype demonstration programs similar to this ICCT project. Over 50 SCR pilot plants were built and operated in western Europe. These pilot plants ranged from 19 to 6200 SCFM and provided the data base that led to commercialization of the SCR technology in western Europe.

Previously completed U.S. work with the SCR process on utility boilers consists of three projects which were carried out in the late 1970s and early 1980s. One of these was carried out on a natural gas fired boiler by Southern California Edison. Another project consisted of a pilot test conducted for the EPA at Georgia Power's Plant Mitchell. This pilot plant treated a 1000 ACFM (0.5 MWe) slip stream of flue gas resulting from the combustion of low-to medium-sulfur coal. A third pilot-scale project, carried out at the Public Service Company of Colorado's Arapaho Station treated a 5000 ACFM (2.5 MWe) slip stream of flue gas resulting from the combustion of U.S. low-sulfur coal.

Although SCR is widely practiced in Japan and Europe, there are numerous technical uncertainties associated with applying SCR to U.S. coals. These uncertainties include:

- (1) potential catalyst deactivation due to poisoning by trace metal species present in U.S. coals that are not present in other fuels.

- (2) performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO_2 and SO_3 .
- (3) performance of a wide variety of SCR catalyst compositions, geometries and methods of manufacture under typical high-sulfur coal-fired utility operating conditions.

These uncertainties will be explored by constructing a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas derived from the combustion of high sulfur U.S. coal.

The first uncertainty above will be handled by evaluating SCR catalyst performance for two years under realistic operating conditions found in U.S. pulverized coal utility boilers. The deactivation rates for the catalysts exposed to flue gas from high sulfur U.S. coal will be documented to determine accurate catalyst life, and thus, accurate process economics.

The second uncertainty above will be explored by performing parametric testing and through the installation/operation of air preheaters downstream of the larger reactors. During parametric testing, operating conditions will be adjusted above and below design values to observe deNOx performance and ammonia slip as functions of the change in operating conditions. Air preheater performance will be observed to evaluate effects from SCR operation upon heat transfer, and therefore, upon boiler efficiency.

The third uncertainty is being handled by using honeycomb- and plate-type SCR catalysts from U.S., Japan and Europe of various commercial composition. Results from the tests with these catalysts will expand our knowledge of performance on a variety of SCR catalysts under U.S. utility operating conditions with high-sulfur coal.

The intent of this project is to demonstrate commercial catalyst performance, proper operating conditions, and catalyst life for the SCR process. This project will also demonstrate the technical and economic viability of SCR while reducing NO_x emissions by at least 80%.

The project will be conducted at Gulf Power Company's Plant Crist Unit 5, a commercially operating 75 MW unit, located in Pensacola, Florida, on U. S.

coals with a sulfur content near 3.0%. Unit 5 is a tangentially-fired, dry bottom boiler, with a hot and cold side ESPs for particulate control. The SCR process to be used in this demonstration will be designed to treat a slip-stream of flue gas and will feature multiple reactors installed in parallel. With all reactors in operation, the maximum amount of combustion flue gas that can be treated is 17,400 standard cubic feet per minute (scfm) which is roughly equivalent to 8.7 MWe.

The proposed SCS facility is a slip-stream SCR test facility consisting of three 2.5 MWe (5000SCFM) SCR reactors and six 0.20 MWe (400SCFM) reactors that will operate in parallel for side-by-side comparisons of commercially available SCR catalyst technologies obtained from vendors throughout the world. Figure 2 presents a simplified process flow diagram for the proposed facility. The large (2.5 MWe) SCR reactors will contain commercially available SCR catalysts as offered by SCR catalyst suppliers. These reactors will be coupled with small-scale air preheaters to evaluate the long-term effects of SCR reaction chemistry on air preheater deposit formation and the deposits' effects on air preheater. The small reactors will be used to test additional commercially available catalysts. This demonstration facility size will be adequate to develop performance data to evaluate SCR capabilities and costs that are applicable to boilers using high-sulfur U.S. coals.

The demonstration project will be conducted over a 52-month period with project activities including environmental monitoring, permitting, design, construction, operation, and process evaluation. The project is organized into three phases: (1) Phase I - Permitting, Environmental Monitoring Plan and Preliminary Engineering; (2) Phase II - Detail Design, Engineering and Construction; and (3) Phase III - Operation, Testing, Disposition, and Final Report. Phase I is scheduled for 4 months, Phase II is scheduled for 20 months and Phase III is scheduled for 28 months. Operations are planned for 26 months. The cooperative agreement was signed June 14, 1990, and the project completion date is projected to be in the fourth quarter of 1994. The total estimated project costs are \$15,574,355. The co-funders are SCS (\$6,049,017), DOE (\$7,525,338), and EPRI (\$2,000,000).

FIGURE 2. PROTOTYPE SCR DEMONSTRATION FACILITY-PROCESS

Section 3

PROJECT DESCRIPTION

Within the three phases of the project, the following tasks will be conducted to effectively demonstrate the SCR process:

Phase I - Permitting, Environmental Monitoring Plan and Preliminary Engineering

- Task 1.1.1 - Prototype Plant Permitting Activities
- Task 1.1.2 - Develop Environmental Monitoring Program
- Task 1.1.3 - Preliminary Engineering
- Task 1.1.4 - Engineering and Construction Contracts Scope Development
- Task 1.1.5 - Project Management and Reporting

Phase II - Detail Design Engineering and Construction

- Task 1.2.1 - Detailed Design Engineering
- Task 1.2.2 - Construction
- Task 1.2.3 - Operation Staff Training
- Task 1.2.4 - Planning for Detailed Testing
- Task 1.2.5 - Start-Up/Shakedown
- Task 1.2.6 - Project Management and Reporting

Phase III - Operations, Testing, Disposition and Final Report

- Task 1.3.1 - SCR Demonstration Facility Operations and Maintenance
- Task 1.3.2 - Process Evaluation
- Task 1.3.3 - Environmental Data Management and Reporting
- Task 1.3.4 - Economic Evaluation
- Task 1.3.5 - Dismantling/Disposition
- Task 1.3.6 - Project Management and Reporting

Section 4 PROJECT STATUS

Progress during October - December, 1990, is summarized below for each of the on-going tasks in the Scope of Work.

PHASE I - PERMITTING, ENVIRONMENTAL MONITORING PLAN AND PRELIMINARY ENGINEERING

Task 1.1.1 - Prototype Plant Permitting Activities

The State of Florida Department of Environmental Regulations (DER) provided written, formal notification to Gulf Power that the SCR pilot plant project at Plant Crist will be exempted from the permitting process. (This notification was based on review by DER of our preliminary process flow diagram. Note below that there is the potential for the process flow diagram to be modified, however we do not expect any process changes to warrant any different decision from the DER.)

Task 1.1.2 - Develop Environmental Monitoring Program

The draft Environmental Monitoring Plan (EMP) prepared by Radian Corporation, as the project's environmental subcontractor, was reviewed by SCS and Gulf Power. Radian incorporated necessary revisions into the EMP and sent the EMP to DOE for their review. Both the Sampling and Analytical Methods, to document the sample acquisition and analysis procedures, and the Quality Assurance/Quality Control Project Plan were developed and included in the EMP.

Task 1.1.3 - Preliminary Engineering

During this reporting period, SCS decided to eliminate Unit 6 (a 320-MW, wall-fired, dry bottom boiler) from the project on the basis of technical discussions with catalyst suppliers, Southern Research Institute's (SRI) duct characterization testing, DynaGen's review of SRI data, and the technical evaluations by SCS. The conclusion is that the existing flue gas conditions on Unit 6 make it impossible to extract a consistent, representative flue gas slipstream for use in the pilot SCR reactors. Test data from SRI's duct

characterization tests and review of these data by DynaGen revealed wide variations in flue gas velocities and flow directions as well as particulate mass loadings at the only available location on Unit 6 where a slipstream can be extracted. (In contrast, the data show ideal conditions for slipstream extraction from Unit 5.) Retaining Unit 6 in the project would jeopardize the technical quality of the data to be produced in the pilot SCR reactors.

The decision to eliminate Unit 6 does not negatively affect the technical value of this project. Substantial data will still be produced on the influence of high-sulfur U.S. coal on commercially available SCR catalyst performance and life. The results of SRI's test data show that there are sufficient variations in NO_x levels from Unit 5 that statistical analyses of the pilot plant data will allow SCR performance as a function of inlet NO_x to be determined from the data that will be developed as part of this project. This type of analysis will provide the information that was sought by including Unit 6 in the original proposal (since Unit 6 NO_x emissions are typically higher than those of Unit 5). More details to the technical rationale for this decision are provided in Appendix A.

SCS personnel visited with Haldor Topsoe in Copenhagen, Denmark and Siemens KWU in Erlangen, Germany to a) review SCR catalyst specifications, b) review SCR pilot plant design/operational experience, and c) to tour existing SCR pilot plants and commercial-scale facilities.

During this reporting period, DynaGen, Inc., a fluid mechanics consulting subcontractor, constructed and completed flow modeling tests with a 1/9 scale model of Plant Crist ductwork. Results indicated that the model flows well represented actual results (from SRI testing) and that there should be no significant deleterious effects on normal Plant Crist operations or flow profiles at the ESP inlet from the pilot plant extraction scoop. The increased pressure drop from introduction of the scoop is only expected to be about 0.11 inches of water. The reactor inlet modeling effort was also initiated. The reactor inlet concept was revised to include the following: a) change from a long vertical downflow duct into the reactor to a horizontal run with round to rectangular duct transition; b) addition of diffuser, equipped with internal baffle plates and expansion in only one dimension; and c) the transition from horizontal to vertical flow into the reactor inlet is equipped

with turning vanes. After considering five alternatives, two design options were chosen for flow model testing at 1/2 scale, and these are shown in Figures 3 and 4. Construction of the models was underway at the end of this reporting period. Arrangements were made to secure suitable dummy layer material for the flow model testing. A status meeting was held with DynaGen on Tuesday, December 4, 1990. The results of the meeting are attached in Appendix B which describe the flow modeling activities in more detail.

Preparation of the SCR process Design Data Book for use by SCS Design Engineering during detailed design continued. Review and revisions of previous work performed on the conceptual design specifications was accomplished, which included the following areas:

- o Mass balances
- o Heat loss calculations
- o Major equipment lists
- o Preliminary piping and instrumentation diagrams
- o Preliminary ammonia storage and distribution system
- o Preliminary extractive gas sampling system
- o Operation philosophy discussion
- o Preliminary discussion of parametric test plans as they might affect design

In particular, draft P&ID drawings and control system logic underwent internal review. The process flow diagram, ammonia control system, and general arrangement drawings were reviewed and revised, including the new control room location. Significant electrical design work was accomplished with the production of single line drawings and a proposed electrical distribution scheme. Field investigations were performed for locating structural columns and preliminary platform design was initiated. Furthermore, preliminary efforts to define air heater/heat pipe/cyclone equipment operating scenarios and specifications were begun. Some details of the description written for the cyclones is included in Appendix C.

Phase I was originally to be completed by the end of November. However, because of several important changes in design which resulted from things learned during the trip to Europe in October, the conceptual design phase increased in duration. A complete Design Data Book will be issued at the

Figure 3

SCR PILOT PLANT REACTOR INLET DUCT
TEST MODEL DESIGN NO. 1
DYNAGEN, INC.
Revised 12/17/90

Figure 4

SCR PILOT PLANT REACTOR INLET DUCT
 TEST MODEL DESIGN NO. 2
 DYNAGEN, INC.
 Revised 12/17/90

conclusion of Phase I which will now likely be during the first quarter of 1991.

One of the main changes in the conceptual design regards the disposition of flue gas and hot air from the pilot plant air heaters. The original process flowsheet called for the pilot plant flue gas, extracted upstream of the hot-side ESP, to be reinjected upstream of the cold-side ESP. The pilot plant hot air from the air heaters would be injected into the hot combustion air exiting the plant air heater. An analysis of heat rate and cold end average impacts from the SCR pilot plant upon Unit 5 was performed and the results are described in detail in Appendix D. In summary, extracting flue gas in front of the Unit 5 air heater for the pilot plant is calculated to exacerbate an existing problem with cold end temperatures. To resolve this problem, several alternative process flow options were identified. The two being most seriously considered and now under evaluation are shown in Figures 5 and 6. This issue is expected to be resolved during the next quarter.

Another issue resulting from experience gained during the European trip involves SCR vendor development experience indicating that catalyst activity loss may vary with the extraction location of the flue gas from the host boiler. Flue gas extracted and treated immediately at the economizer wall can show higher trace metal concentrations and lead to higher catalyst poisoning. Extracting and treating flue gas after long duct runs with cooler gas temperatures may allow vapor phase metal condensation. When extracted in this manner for a pilot plant, it is possible that the catalyst may not be exposed to the actual trace metal concentration that the catalyst would see on a commercial system. (See Figure 7.) Reheating the flue gas, once it has cooled, does not solve the problem, since once the trace metals condense out on the ash, the temperature required to revaporize these compounds is much higher than the SCR operating temperature.

As a result of the above, the addition of an economizer bypass line is being evaluated for this project. (See Figure 8.) The economizer bypass would be used only as needed to maintain a minimum temperature for the total flue gas entering the SCR pilot plant, usually at low loads. At full load, the bypass would probably be closed. This mode of operation would allow the SCR pilot plant operation to more closely resemble that of a commercial system, which

Figure 5

FLOW SCHEMATIC FOR DISPOSITION OF HOT AIR AND
FLUE GAS FOR SCR PILOT PLANT AT CRIST UNIT 5

Figure 6

FLOW SCHEMATIC FOR DISPOSITION OF HOT AIR AND
FLUE GAS FOR SCR PILOT PLANT AT CRIST UNIT 5

Figure 7

Effect Of Pilot Plant Location On Catalyst Activity

Figure 8

USE ONLY ONE OF SEVERAL POTENTIAL
SITES FOR ECONOMIZER BYPASS

SCHEMATIC OF POTENTIAL ECONOMIZER BYPASS
FOR SCR FACILITY AT PLANT CRIST

normally has an economizer bypass, and would allow the exposure of the catalysts to any potential poisons, therefore, more accurately reflecting the catalyst activity which would be experienced on a full-scale SCR system. This economizer bypass concept is currently being evaluated for feasibility with Unit 5 operations, with respect to existing tie-in locations, temperature profiles, line sizing, etc. In addition, other alternatives which are being considered for implementation include (a) locating a reference reactor, which contains a duplicate of one of the test catalysts, near the economizer; and (b) installing test catalyst coupons to determine the potential severity of catalyst poisons.

Based on the preliminary definition of utility needs from, and interface points with, Plant Crist, a meeting was held with Gulf Power Engineering to review interfaces between the SCR pilot plant and Plant Crist. Interfaces include: electrical, steam, water, air and flue gas systems. Proposed interface points are under review by Gulf.

SCS review of detailed catalyst specifications was completed. Supplemental information from each supplier was requested in order to finalize SCR reactor internal design. One vendor requested a change in the type of catalyst that they will supply to the project and this change was conditionally approved, based upon receipt and approval of similar specifications as previously received for the former catalyst type.

The project management information system (MIS) for engineering and construction developed during the last reporting period continued to be implemented.

Task 1.1.4 - Engineering and Construction Contracts Scope Development

Because of the delays in the conceptual design portions resulting from significant design changes, limited progress was made on this task during this reporting period. Work is planned for the first quarter of 1991.

Task 1.1.5 - Project Management and Reporting

The MIS, developed for tracking overall budget and schedule information, was

used to control budget and schedule and to help fulfill DOE reporting requirements. Monthly reports were submitted, and the Project Evaluation Plan for Phases I and II, submitted for review to DOE during the first reporting period, was approved.

Evaluation Agreements with Siemens and Haldor Topsoe were successfully negotiated and signed. This completed the negotiations with all the catalyst vendors which will be participating in the project.

Coordination meetings with Design Engineering were conducted on a weekly basis and a preliminary plant interface issue meeting was held with Gulf Power. An informal status briefing was held with the DOE project officer on December 18, 1990.

There was a transition in SCS project management for this project as J. D. Maxwell replaced K. W. Bowers as SCS project manager.

Section 5
PLANNED ACTIVITIES

During the January - March, 1991 quarter, the following activities are planned:

- o Complete the Design Data Book, to include: process design documentation, including piping and instrumentation diagrams, ammonia storage and distribution system, and ductwork and inlet ductwork design.
- o Complete reactor flow modeling and perform flow mixing and injection design calculations for ammonia injection and economizer bypass.
- o Obtain further requested catalyst data and complete reactor internal design and catalyst supplier scope of supply.
- o Complete construction contract scope development.
- o Begin portions of Phase II, detailed engineering design, including development of air heater/heat pipe specifications, control room layout, and electric equipment specifications.
- o Complete preliminary interface design between the SCR facility and Plant Crist.

APPENDIX A

Rationale for Deleting Unit 6 from the SCR Project

ATTACHMENT 1

Technical Rationale for Elimination of Unit 6

Unit 6 will be dropped from the project for the following reasons:

- a. Detailed technical discussions have been held with catalyst suppliers during Phase 1 in order to finalize SCR pilot reactor design criteria. These discussions have revealed substantial differences in SCR reactor designs that would be used if the higher inlet NO_x levels found by SRI from Unit 6 testing (on 7/28/90 - 8/7/90) were to be included in the design basis. Moreover, it is already known that a reactor/catalyst system that is designed for Unit 5 inlet NO_x levels will not perform as well if Unit 6 flue gas were to be introduced (not enough catalyst volume, consequently space velocities would be too high).
- b. Recent data from Unit 5 indicate that inlet NO_x levels could vary by as much as 150 ppm (i.e. between 250 and 400 ppm depending upon unit load and excess O₂), which is sufficient to evaluate the response of SCR to changes in inlet NO_x. This evaluation can be accomplished by recording inlet NO_x level as part of the statistical data analyses and analyzing deNO_x performance as a function of inlet NO_x.
- c. By maintaining the original design concept of periodically ducting Unit 6 flue gas into reactors that are designed for (and primarily operated on) Unit 5 flue gas, the possibility exists of introducing higher levels of trace metal catalyst poisons from Unit 6 flue gas onto the catalyst. Subsequent catalyst composition analyses will be made more difficult since the flue gas source over the catalyst would have varied between two different sources and it will not be possible to determine the origin of trace metal contamination.
- d. Unit 6 is an uncontrolled, "first generation" wall-fired burner equipped boiler. Consequently, its flame zone combustion conditions are typical of high-combustion intensity boilers. The flue gas generated from such a combustion zone will likely be different than that of the type generated by the mixing controlled and O₂-diffusion controlled tangentially-fired Unit 5 boiler. Moreover, as a practical matter it is unlikely that SCR would ever be installed on an uncontrolled wall-fired boiler without first retrofitting low-NO_x burners. LNB retrofits would be more likely to produce a mixing and O₂-diffusion controlled flame (i.e. trending toward a t-fired mode), which validates the use of Unit 5 as a source of flue gas.
- e. Finally, detailed site inspections and data collected in the field by SRI and analyzed by DynaGen, Inc. confirm that extracting a representative slipstream of flue gas from Unit 6

ahead of the air preheater will be a formidable, if not impossible, task. The flue gas velocities and particulate mass loadings vary dramatically over the duct area available for an extraction scoop location due, in large part to the host boiler duct configuration (see Figures 1 and 2). It is highly unlikely that a representative sample of flue gas could be consistently extracted from Unit 6 for use in the pilot plant.

For the reasons outlined above, Unit 6 has been dropped from the project.

FIGURE 1

SKETCH OF UNIT 6 FLOW CONFIGURATIONS

FIGURE 2

APPENDIX B

Results of Flow Modeling Meeting
with Dynagen on December 4, 1990

DATE: December 11, 1990
RE: Meeting with Dynagen about Flow Modeling for SCR Pilot Plant
FROM: J. D. Maxwell
TO: H. R. Bailey
~~_____~~
E. C. Healy
G. S. Ranhotra
R. E. Rush
R. E. Sears

A meeting was held on Tuesday, December 4, 1990, to discuss the flow modeling activities for the Selective Catalytic Reduction Clean Coal Technology project. Those attending included:

Dynagen
Gerald Gilbert

SCS
Kerry Bowers
Ed Healy
Doug Maxwell
Rick Ranhotra
Rod Sears

The major highlights of the meeting are described below.

1. Mr. Gilbert presented the status of work being conducted by Dynagen, which is summarized in Attachment I.

Task 1 - Flow modeling main flue gas duct and effect of scoop:
Model construction was completed and qualitative study (visual - including a video of flow patterns) was done on both dummy and working scoops. Quantitative testing for velocity profile and pressure drops was completed only on dummy scoops, but quantitative testing is underway and may be completed this week on the working scoop. This work is being done simulating gas flows at full, low, and one-half of full loads. See Figure 1 of Attachment II. The preliminary results indicate that any changes to flow introduced by the scoop are dampened

out by the time the flue gas enters the downstream ESP. Therefore, flue gas patterns entering the ESP do not "know" the scoop is there. (Other results are discussed under Task 3 below.)

Task 2 - NH₃ injection system:

Preliminary assessment of duct lengths needed to achieve uniform mixing ($\pm 5\%$) of NH₃ for a single injection point indicates a range of 20 to 40 pipe diameters. This translates to 40 to 80 feet for our 2 foot diameter pipe. Mr. Gilbert said that this range would be reduced about proportionately with the increase in number of injection points, i.e., for four multiple NH₃ injection points, the range of pipe diameters needed to ensure uniform mixing would be about 5 to 10.

A computer program entitled "Phoenix" will be used in final evaluation of alternative nozzles, duct design, and to estimate NH₃ concentration profile over the cross-section.

Task 3 - SCR reactor inlet gas flow control:

Data presented in Table 1 of Attachment II indicates there should not be a problem in dust stratification in pilot plant ducts. However, by taking gas from the main duct with the scoop and reducing the main gas velocity, the potential for fallout in the main duct is increased, primarily at low boiler loads. When asked if such a build-up of ash should occur between the scoop and ESP inlet, will this ash re-entrain when the pilot plant is not operating, Mr. Gilbert answered that it is unlikely because the highest velocity is only about 46 fps while at least 60 fps is required for re-entrainment. It was noted that after the pilot plant operation commences, it would be worthwhile to inspect this portion of the main flue gas duct (scoop take-off to ESP inlet) at every opportunity that Unit 5 is down, and if necessary, remove any ash build-up. (We will ask Gulf Power if this is a problem now.)

Figures 3 and 4 of Attachment 2, iso-velocity contours of Unit 5 duct model, show that the model represents the actual plant duct very well (usually $\pm 2-3\%$ variation).

Potential consequences of introducing the scoop into the main flue gas duct were discussed and conclusions reached by Dynagen are given in Table 2 of Attachment 2. (1) Increased pressure drop - As shown in Figure 2 of Attachment 2, there is only about half a duct velocity head, or 0.11 inches of water pressure loss created by the scoop. (2) Velocity profile at the hot ESP inlet - As indicated in Figures 5 and 6, the distance between the scoop and ESP is sufficient to allow almost equivalent velocity profiles at the ESP inlet with or without the scoop. (3) Dust accumulation in the scoop at no flow - During periods when the pilot plant is not operating but Unit 5 remains on-line, ash build-up may occur in the scoop. Alternative solutions discussed included installing an adjustable "flap" over the scoop inlet which could be closed when the pilot plant is not operating and the addition of equipment for blowing the ash out before each pilot

plant startup. However, the best course of action was discerned to be that of making no design changes, and just ensure that we use the reactor bypasses upon each startup. This would prevent any significant ash loading which may pass through the pilot plant (from the ash build-up in the scoop) from damaging the catalyst in the reactor. (4) Vibration of downstream vanes in main duct - Although there will be a slight increase in forces acting on the vanes, it is not expected to be a problem. If it did become a problem, stiffeners could be added for additional support. (5) Scoop location - If it became necessary to reduce pressure loss or unsteady forces on the vanes, the scoop could be moved upstream 9 to 12 feet and produce equivalent velocity profiles.

A video of the model flow pattern work done to date with the scoop in place was shown by Mr. Gilbert with high and low velocities and with and without the scoop in operation. The scoop geometry shown in the video is given in Figure 7 of Attachment II. (We will make a copy of this video for internal distribution and we discussed plans for SCS personnel to visit Dynagen to witness testing of the reactor inlet models.) We also discussed the fact that vanes will not be needed in the pilot plant flue gas takeoff line past the transition from rectangular to round duct, if long radius bends are maintained in the round sections.

2. The concept of the economizer by-pass line was briefly discussed. Mr. Gilbert will review further and will make recommendations on how to introduce the economizer bypass gas stream into the main pilot plant gas takeoff stream to provide the best mixing results. He did suggest that we locate the temperature control for the total flue gas stream to the reactors (which will adjust the damper controlling the amount of economizer bypass gas stream that will be mixed with the main pilot plant gas takeoff stream to provide the proper flue gas temperature entering the reactor) as far down stream as possible from the mixing point of these two gas streams to allow sufficient time for mixing - and thus a more accurate temperature reading.
3. The reactor inlet modeling effort was discussed, using the slides from the SCS European trip to describe the recently revised concepts, which include: diffuser, equipped with internal baffle plates, from round to rectangular duct should expand in only one dimension; and the transition from horizontal to vertical flow should expand in the second dimension and be equipped with turning vanes. Mr. Gilbert, having had the opportunity to previously review this revised concept, presented five alternative reactor inlet transition designs, shown in Attachment III. The following summarizes the results of our discussions on these five alternatives:

a - Alternatives 1 and 2 were eliminated from consideration primarily because of physical dimension constraints of our pilot plant. Instead, Dynagen will be able to model both alternative 3 and 5 for

us. Mr. Gilbert will choose the proper number of turning vanes but each case will contain the greater number of smaller vanes, as depicted in the Alternative 5 sketch in Attachment III, to reduce the required distance for the gas flow to smooth out downstream of the vanes.

b - These models will be built so that the dummy layer distance from the turning vanes in the horizontal to vertical bend for the reactor inlet can be adjusted.

c - The depth of the dummy layer will be adjusted by securing enough material to provide 2 layers.

d - One of the materials tested will be in a similar shape as the honeycomb catalyst with approximately 7 mm pitch and 1.2 mm wall thickness. The depth will be 1 foot. Another material with much wider flow openings (e.g., steel grating grid with 1/2 to 2 inch spacings), which would require greater lengths in actual practice to smooth out the flow, may also be tested.

e - Per Mr. Gilbert's recommendation, additional duct will be added for a round to rectangular transition piece prior to the first expansion with baffle plates. This will be one duct diameter. See alternative 1 and 2 sketches.

f - The models will be built to about half scale, i.e. dimensions of 1.5 feet by 2 feet. On this basis, about 12 elements of the honeycomb dummy material will be required (about 6" by 6" dimensions) per dummy layer. Results from these models can be extrapolated to the small SCR pilot plant reactors as well.

Mr. Gilbert expected results may be available from this flow modeling effort as early as mid-January.

4. Mr. Gilbert provided an estimate of \$16,535.69 as the cost for December work which we will need to accrue for 1991 billing.

ATTACHMENT I

STATUS OF WORK BEING CONDUCTED BY DYNAGEN FOR THE SCR PILOT PLANT PROJECT

Gerald B. Gilbert, DynaGen, Inc. December 4, 1990

Task	Description	Work Completed	Work to Be Completed
1.	<p><u>Effect of Scoop on Power Plant Flue Gas Flow</u></p> <p>A. Design and Build Duct System From Boiler Outlet To ESP Inlet.</p> <p>B. Build Model Scoops</p> <p>C. Test the Effect of Scoop On Main Duct Flow</p> <p>D. Specify Take Off Scoop Geometry</p>	<p>A(1) Model built and assembled.</p> <p>B(1) Three dummy scoops and one working scoop were constructed.</p> <p>C(1) Three dummy scoops were tested for velocity profile and pressure loss in the main duct.</p> <p>C(2) Working scoop was evaluated visually.</p> <p>C(3) A video of flow patterns was taken.</p>	<p>C(1) Quantitative tests on working scoop to be conducted at several main duct flows.</p> <p>D(1) To be done at completion of test work.</p>

ATTACHMENT I

Page Two

Task	Description	Work Completed	Work to Be Completed
2.	<p>E. Prepare Report</p> <p><u>Ammonia Injection System</u></p> <p>Evaluate Alternatives For Injection Method And Location to Achieve a $\pm 5\%$ Uniformity At Reactor Bed Inlet Face.</p>	<p>(1) Jet mixing equations were used to develop a preliminary assessment of duct lengths needed to achieve uniform mixing of Ammonia.</p> <p>A(1) Submitted on September 18, 1990.</p>	<p>E(1) To be done at completion of test work</p> <p>(1) An analytical computer solution for mixing will be used to evaluate alternative nozzles and locations in the final duct geometry and to recommend a good design.</p>
3.	<p><u>Prototype SCR Reactor Inlet Gas Flow Control</u></p> <p>A. Prepare A Brief Report On Pilot Plant System Layout And Control</p>		

ATTACHMENT I

Page Three

Task	Description	Work Completed	Work to Be Completed
4.	B. Evaluate Potential For Dust Stratification In Pilot Plant Ducts And Fallout In Main Duct	B(1) Preliminary conclusions to be discussed on 12/4/90.	(1) This will be done when the duct design is finalized.
	C. Calculate Pressure Loss of Pilot Plant Pipe Components	C(1) None.	
	<u>Reactor Inlet Design</u>		
	A. Review Initial Design And Comment On Possibility to Meet $\pm 10\%$ Flow Uniformity At Reaction Bed Inlet	A(1) Submitted evaluation letter on October 4, 1990. A(2) Affect of dummy reactor bed on flow uniformity distribution to be discussed at meeting on 12/4/90.	

ATTACHMENT I

Page Four

Task	Description	Work Completed	Work to Be Completed
	<p>B. Suggest Alternative Designs Based On The Siemens Double Diffuser Approach</p> <p>C. Experimentally Optimize the Reactor Inlet Using A Laboratory Flow Model</p>	<p>B(1) Alternatives to be presented at the meeting on 12/4/90</p> <p>C(1) None</p>	<p>C(1) Model of selected alternatives to be built and tested.</p>

ATTACHMENT II

FIGURE 1 EXTENT OF MODEL AND LOCATION OF TRAVERSES AND SCOOP

1/4 in. scale model

ATTACHMENT II

TABLE 1

FLY ASH SETTLING IN PILOT
PLANT DUCTS AT 60 FPS

normal fly ash
settling test
data

Weight %	Less than μ (microns)	Terminal Velocity FPS	Downward movement In 1 second or 60 feet
95	90	1.10	13.2"
90	57	0.44	5.3"
80	38	0.196	2.35" ←
60	21	0.060	0.72"
50	16	0.035	0.42"
40	13	0.023	0.28"
20	6.6	0.0059	0.071"
10	3.4	0.0016	0.019"
1	1.1	0.00016	0.0019"

ATTACHMENT II

TABLE 2

TABLE DISCUSSION OF SCOOP POTENTIAL PROBLEMS FOR
SCR PILOT PLANT UNIT 5 DUCT BETWEEN
BOILER AND HOT ESP

Potential Problem	Method of Evaluation	Conclusion Reached
Increased Pressure Loss In Main Duct Due To Scoop.	Pressure Loss Measurement On A Gas Flow Model.	Increase Will Be About Half A Duct Velocity Head Or 0.11 Inches of Water.
Velocity Profile At The Hot ESP Inlet.	Velocity Measurements On A Gas Flow Model.	The Wake Created By The Scoop Disappears Before Reaching The ESP Inlet. Velocity Profiles Are Nearly The Same.
Dust Accumulation In The Scoop At No Flow.	Flow Pattern Observations On A Gas Flow Model.	As The Gas Diverts Around The Scoop Dust May Deposit Inside The Scoop.
Vibration Of Downstream Vanes In Main Duct.	Flow Pattern Observations On a Gas Flow Model.	In Normal Operation There Is A Flow Separation On Each Vane From Top To Bottom. In Addition To This The Scoop Will Cause The Velocities To Be Higher And The Scoop Wake Will Also Intersect With The Vanes. This Will Increase The Unsteady Forces Acting On The Vanes.
Scoop Location	Tested When Located Between Field Traverse Station And First Downstream Duct Bond.	Moving Upstream Will Reduce Pressure Loss And Unsteady Forces On The Elbow Vanes. Velocity Profiles Are Nearly As Good 12 Feet Further Upstream.

ATTACHMENT II

FIGURE 2 PRESSURE LOSS IN
MAIN DUCT UNIT 5 FLOW DUE
TO PRESENCE OF SCOOP WITHOUT
PILOT PLANT FLOW

HIGH FLOW $V_{H_{INLET}} = 0.224$ "WATER

OPEN SYMBOLS - NO DOWNSTREAM
SHAPE

SOLID SYMBOLS - WITH DOWN STREAM
SHAPE

ATTACHMENT II

FIGURE 3 ISO-VELOCITY CONTOURS
 SCR PILOT PLANT PROJECT UNIT 5 DUCT MODEL
 Traverse Location UPSTREAM OF SCOOP
 Flow Condition FIELD HIGH FLOW CONDITION
 Simulated Duct Flow 197,860 ACFM
 Simulated Scoop Flow NO SCOOP IN PLACE

ATTACHMENT II

FIGURE 4 ISO-VELOCITY CONTOURS
 SCR PILOT PLANT PROJECT UNIT 5 DUCT MODEL
 Traverse Location NEAR ESP INLET
 Flow Condition FIELD HIGH FLOW CONDITION
 Simulated Duct Flow 197,860 ACFM
 Simulated Scoop Flow NO SCOOP IN PLACE

Percent of Average Velocity

Flow Out of Paper

ATTACHMENT II

FIGURE 5 ISC-VELOCITY CONTOURS
 SCR PILOT PLANT PROJECT UNIT 5 DUCT MODEL
 Traverse Location NEAR ESP INLET
 Flow Condition FIELD HIGH FLOW CONDITION
 Simulated Duct Flow 197,860 ACFM
 Simulated Scoop Flow SCOOP IN PLACE / ZERO FLOW

ATTACHMENT II

FIGURE 6 VERTICAL VELOCITY PROFILE
ON CENTERLINE OF DUCT AT TRAVERSE
STATION 3 FOR UNIT 5 DUCT MODEL

⊙ EXISTING DUCT WITHOUT SCOOP
X 22% BLOCKAGE SCOOP WITH ZERO FLOW

FIGURE 7 SCOOP GEOMETRY
SHOWN IN VIDEO

11 CIRCULAR ARC
VANES 9" RADIUS
EQUALLY SPACED

$Q = 36,356$ ACFM

LOC.	AREA FT ²	VELOCITY FPS
1	13.0	46.6
2	11.24	53.9
3	10.10	60.0

Technical drawing of a ship's hull cross-section. The drawing shows the internal structure, including the keel, bottom plating, and various stiffeners. Key dimensions and features are labeled:

- 2' 4"**: Dimension for the width of the hull at the bottom.
- 1.54'**: Dimension for the width of the internal structure.
- 3'**: Dimension for the width of the hull at the top.
- 4'**: Dimension for the height of the hull.
- 2'**: Dimension for the height of the internal structure.
- 20.7° INCLUDED**: Angle of the internal structure.

[illegible]

ATTACHMENT III

ALTERNATE 2
REACTOR INLET

ATTACHMENT III

ATTACHMENT III

ATTACHMENT III

ALTERNATE 5
SCALE VERSION
OF SCS SKETCH

APPENDIX C
Technical Description of
Cyclone Operation

SCS/DOE SELECTIVE CATALYTIC REDUCTION PROJECT TECHNICAL DESCRIPTION OF CYCLONE OPERATION

Selective Catalytic Reduction Pilot Plant

Selective Catalytic Reduction (SCR) is a post combustion NO_x control technology which is widely used on low sulfur fuels in Japan and Europe. The technology involves injecting ammonia into the flue gas stream which reacts over a catalyst. The catalyst which is housed in a reactor is typically installed between the boiler economizer exit and the air preheater, thus subjected to high operating temperatures (620° F to 750° F) and full particulate loading of flyash.

SCR technology, while technically feasible, has many unknowns when applied to high-sulfur, US coals. In conjunction with the US Department of Energy (DOE), Southern Company Services (SCS) plans to design/construct/operate a 9 reactor pilot plant to test various types of SCR catalysts. The pilot plant consists of three large reactors nominally sized at 5000 scfm each and six small reactors nominally rated at 400 scfm each. **(NOTE: FOR THIS PROJECT, STANDARD CONDITIONS ARE 0° C (32° F) AND 1 ATMOSPHERE)** Two of the large reactors will be equipped with rotary type Ljungstrom air preheaters which are subject to air leakage from the air side to the gas side. The remaining large reactor will be equipped with a heat pipe air preheater and is not subject to air leakage. All three large reactors will have cyclones downstream of the air preheaters and upstream of the flue gas booster fan. Five of the six small reactors will have cyclones downstream of the reactor and upstream of the booster fan. One of the six small reactors will be on "low dust" service with a flue gas source downstream of a hot side electrostatic precipitator.

Operational Scenarios

The pilot plant is designed to operate at many different conditions to allow steady state and transient testing of the different catalysts. The three major process variables which can be manipulated are: (1) flue gas temperature; (2) ratio of ammonia feed to the amount of NO_x present in the flue gas (NH₃/NO_x); and (3) flue gas flow rate.

Large Reactor Steady State Operation

During normal operation, the large reactors will be operation at steady state around a set of design conditions. Once the gas

passes through the reactor, it enters an air heater and is cooled to approximately 300° F. (See Figure 1) The predicted flue gas conditions at the large reactor cyclone inlet are shown below in Table I.

Table I - Large Reactor Steady State Operating Conditions

	Ljungstrom APH	Heat Pipe APH
Number of Cyclones	2	1
Flue gas flowrate	9404 acfm	8072 acfm
Flue gas temperature	300° F	300° F
Inlet gas velocity	60 ft/sec	60 ft/sec
Ash flow rate	150 lb/hr	150 lb/hr

Note: Preliminary design considers one cyclone for each reactor

Large Reactor Off-Design Operation

The pilot plant will periodically operate at various off-design conditions to stress the catalyst performance and quantify the deactivation rate. These off-design conditions involve variations of flue gas flow and temperature. The large reactor trains are equipped with an air preheater bypass which operates when the reactor is operated at any condition other than the design point. (See Figure 2) Therefore, there is no air preheater leakage to consider when the reactor is operated at any condition other than the design point. Each bypass line is equipped with a finned tube heat exchanger to cool the gas to approximately 300° F when entering the cyclones. However, during off-design operation, the bypass heat exchanger is likely to either plug causing the thermal performance to decline or over-perform and cause flue gas temperatures less than 300° F. It is likely that the cyclone inlet will operate somewhere between 250° F and 500° F during off-design conditions.

The flue gas flow ranges roughly from 60% to 150% of design flow. Flow rate will be controlled using variable speed fans.

The off-design operation of the large reactors can best be visualized in a matrix form as shown below in Table II. The center of the matrix represents the steady state flow condition specified above. The cyclones will likely operate anywhere inside the matrix during off-design operation.

Table II - Large Reactor Off-Design Operating Matrix

		<u>Nominal Flowrate</u>		
		7500 SCFM	5000 SCFM	3000 SCFM
T e m p e r a t u r e	450° F	Flow: 14497 ACFM Temp: 450° F Velocity: 95 f/s Ash: 225 lb/hr	Flow: 9665 ACFM Temp: 450° F Velocity: 64 f/s Ash: 150 lb/hr	Flow: 5799 ACFM Temp: 450° F Velocity: 38 f/s Ash: 90 lb/hr
	300° F	Flow: 12108 ACFM Temp: 300° F Velocity: 80 f/s Ash: 225 lb/hr	Steady State Operating Point	Flow: 4843 ACFM Temp: 300° F Velocity: 32 f/s Ash: 90 lb/hr
	250° F	Flow: 11311 ACFM Temp: 250° F Velocity: 74 f/s Ash: 225 lb/hr	Flow: 7541 ACFM Temp: 250° F Velocity: 50 f/s Ash: 150 lb/hr	Flow: 4524 ACFM Temp: 250° F Velocity: 30 f/s Ash: 90 lb/hr

Note: Nominal flow rate are at standard conditions of 0° C (32° F) and 1 atm.

Small Reactor Steady State Operation

Similar to the large reactors, the small reactors will be operation at steady state around a set of design conditions. Because there are no air preheaters cooling the flue gas on the small reactors, the cyclones will operate at the full temperature of the flue gas. The small reactors are ganged into groups of three as shown in Figure 3. The predicted flue gas conditions at the small reactor cyclone inlet are shown below in Table III.

Table III - Small Reactor Steady State Operating Conditions

Number of cyclones	5
Flue gas flowrate	976 acfm
Flue gas temperature	700° F
Inlet gas velocity	60 ft/sec
Ash flow rate	12 lb/hr

Note: Preliminary design considers one cyclone for each reactor

Small Reactor Off-Design Operation

Similar to the large reactors, the small reactors will also operate in off-design conditions. You will notice that the small

reactors are manifolded in groups of three. (Figure 3) The operation criteria of the pilot plant is to let any one of a group of three operate in an off-design mode while maintaining the other two reactors in a steady state operation. The small reactor banks contain no air preheater, no finned tubed heat exchanger, and no bypass. Therefore, the cyclone is subject to all temperature and flow variations of a small reactor.

Temperature variation will range between 620° F and 750° F during off-design conditions. The flue gas flow ranges roughly from 60% of design flow to 150% of design flow for each reactor. The range of off-design operation is shown below in Table IV.

Table IV - Small Reactor Off-Design Operating Matrix

		<u>Nominal Flowrate</u>		
		600 SCFM	400 SCFM	240 SCFM
T e m p e r a t u r e	750° F	Flow: 1527 ACFM Temp: 750° F Velocity: 80 f/s Ash: 18 lb/hr	Flow: 1018 ACFM Temp: 750° F Velocity: 54 f/s Ash: 12 lb/hr	Flow: 611 ACFM Temp: 750° F Velocity: 32 f/s Ash: 7 lb/hr
	700° F	Flow: 1463 ACFM Temp: 700° F Velocity: 77 f/s Ash: 18 lb/hr	Steady State Operating Point	Flow: 585 ACFM Temp: 700° F Velocity: 31 f/s Ash: 7 lb/hr
	620° F	Flow: 1363 ACFM Temp: 620° F Velocity: 72 f/s Ash: 18 lb/hr	Flow: 908 ACFM Temp: 620° F Velocity: 48 f/s Ash: 12 lb/hr	Flow: 545 ACFM Temp: 620° F Velocity: 29 f/s Ash: 7 lb/hr

Note: Nominal flow rate are at standard conditions of 0° C (32° F) and 1 atm.

Desired Cyclone Removal Efficiencies

The highest practical removal efficiency is desired at the steady state design point. Realizing that the tradeoff between removal efficiency and pressure drop across the cyclone is important, we generally have some flexibility, within reason, to compensate for higher than normal cyclone pressure drop with the design of the new booster fans. After the cyclone has been sized for the steady state operating point, the high and low removal efficiencies and pressure drops should be calculated using any of the off-design conditions for both the large and small reactor cyclones. It is desired that performance of the cyclone be

bracketed between a best removal, highest pressure drop case and a worst removal, lowest pressure drop case with the steady state operating case somewhere in between.

Flue Gas Particle Size Distribution

Cumulative particle size distributions of the flue gas are shown below in Table V. This data is reproduced from Southern Research Institute duct testing.

Table V - Cumulative Particle Size Distribution

Weight Percent	Particle size less than (μ)
95	90
90	57
80	38
60	21
50	16
40	13
20	6.6
10	3.4
1	1.1

Flue Gas Composition

Table VI shows the predicted flue gas composition for the large and small reactors at the steady state design point.

Table VI - Flue Gas Composition At Steady State Operation

Component	Large Reactors		Small Reactors	
	lb/hr	Weight %	lb/hr	Weight %
CO ₂	5095	17.36	408	20.45
O ₂	1857	6.33	66	3.31
N ₂	20667	70.41	1382	69.27
SO ₂	118	0.40	9.44	0.47
SO ₃	2.23	0.01	0.20	0.01
NO	1.90	0.01	0.15	0.01
NO ₂	0.15	0.0005	0.01	0.00
HCl	3.16	0.01	0.25	0.01
H ₂ O	1456	4.96	117	5.86
NH ₃	0.012	0.00	0.0048	0.00
ASH	150	0.51	12	0.60
TOTAL	29352	100	1995	100

CYCLONE1.doc
1/17/91
ech

FIGURE 1
LARGE REACTOR STEADY STATE OPERATION

CYCLONE INLET CONDITIONS

FLOW: 9404 ACFM (Ljungstrom APH)
8072 ACFM (Heat Pipe APH)
GAS TEMP: 300 F
VELOCITY: 60 ft/s
ASH LOADING: 150 LB/HR

FIGURE 2
LARGE REACTOR OFF-DESIGN OPERATION

FIGURE 3
SMALL REACTOR OPERATION

CYCLONE INLET CONDITIONS (STEADY STATE)

FLOW: 976 ACFM
GAS TEMP: 700 F
VELOCITY: 60 ft/s
ASH LOADING: 12 LB/HR

CYCLONE INLET CONDITIONS (OFF-DESIGN)

FLOW: 1527 ACFM (max) - 545 ACFM (min)
GAS TEMP: 750 F (max) - 620 F (min)
VELOCITY: 80 ft/s (max) - 29 ft/s (min)
ASH LOADING: 18 LB/HR (max) - 7 LB/HR (min)

APPENDIX D

Heat Rate and Cold End Average Impacts
on Plant Crist Unit 5 Air Heater

UNIT 5 SCR PROJECT
HEAT RATE AND COLD END AVERAGE IMPACTS

INTRODUCTION

At the request of E. C. Healy, the impact of operations on the Gulf Power Company Plant Crist Unit 5 due to extraction of flue gas for use in the SCR Project was examined.

Flue gas from the Unit 5 boiler is split before passing through a hot side precipitator, two air preheaters (one per side), and a cold side precipitator before being combined again at the induced draft fan. For the SCR Project, 86,201 lb/hr of flue gas is to be extracted from the duct on one side in front of the hot side precipitator. Plans are to reinject the flue gas into the duct on the same side in front of the cold side precipitator. The gas that will be reinjected will be 95,214 lb/hr at 300°F. The reinjected flow is greater than the flow extracted due to air inleakage from an air heater involved with the SCR Project.

BASIS OF EXAMINATION

The following information was provided for use in this examination:

1. Full load flue gas flow from boiler is 904,022 lb/hr including 5,464 lb/hr of ash. Low load flue gas flow from boiler is 655,416 lb/hr including 3,994 lb/hr of ash.
2. Net plant heat rate is 11,000 BTU/kwh. Net generation at full load is 83 MW and net generation at low load is 45 MW.
3. Coal HHV is 12,200 BTU/lb. Coal analysis is carbon, 67.80 %; hydrogen, 4.6 %; nitrogen, 1.4 %; sulfur, 2.9 %; chlorine, 0.25 %; oxygen, 5.65 %; water, 7.9 %; and ash, 9.5 %.
4. Flue gas temperature in the hot side precipitator averages 650°F at full load and 592°F at low load.
5. Flue gas is to be extracted from one side in front of the hot side precipitator at the flow rate of 86,201 lb/hr at all unit loads.

6. The SCR Project will be in operation during the years 1992 and 1993.

The following assumptions were made:

1. Air preheater performance is as predicted in the boiler contract data.
2. Air temperature at the inlet to the air preheater is 100°F. This is per the original boiler contract and assumes either that hot air from the boiler house space is being used for combustion air or steam coil air heaters are used to preheat the combustion air. If atmospheric air without preheat is entering the air preheater, performance will be worse than predicted during this examination.

HEAT RATE IMPACT

Air preheater performance was modeled at full and low loads with and without flue gas being extracted for the SCR Project. The results of the model can be found on the attached table "Crist Unit 5 Air Preheater Performance". Please note that the results of the model are approximate due to the minimum information available and assumptions which had to be made.

The model showed a loss in air temperature at the air preheater outlet of 3°F at full load and 53°F at minimum load. This results in an increase of unit heat rate of 4 BTU/kwh at full load and 98 BTU/kwh at low load. The value of the heat rate increase for the years 1992 and 1993 is \$39,430 (present worth dollars in 1990).

COLD END AVERAGE TEMPERATURE

The original design coal for Crist Unit 5 contained 0.8 percent sulfur. Operation utilizing this coal would require a minimum cold end average temperature, the average of the inlet air and outlet flue gas temperatures of the air preheater, of 155°F. The coal now being fired contains 2.9 percent sulfur and requires a minimum cold end average temperature of 183°F. Cold end average temperature is specified to protect the cold end of the air preheater from corrosion due to temperatures below the acid dew point temperature.

Based on air preheater performance modeled from the boiler contract data, flue gas temperatures at the hot side precipitator reported at full and minimum load, and an assumed air temperature entering the air preheater of 100°F, cold end average temperatures for Crist 5 are calculated as follows:

Full load - 183°F
Minimum load - 154°F

The calculated cold end average temperatures indicated that there is a cold end average temperature problem at minimum load under present operation.

If the cold end average temperature is calculated with the flue gas being extracted for the SCR Project, the cold end average temperatures are as follows:

Full load - 139°F
Minimum load - 115°F

Additionally, the flue gas temperature exiting the air preheater are calculated as 177°F at full load and 130°F at minimum load.

Please note that based on the criteria used for this examination, there is a flue gas temperature problem on Crist 5 at lower loads during normal operations. Extracting flue gas in front of the air preheater only increases what is apparently an existing problem.

HOT AIR INJECTION

There is 66,204 lb/hr of air at 600°F available from the SCR Project which could be injected into the duct in front of the air preheater to replace the flue gas which is to be extracted. If this is done, it is likely that the flue gas discharged from the SCR Project will have to be injected directly into the stack to keep from overloading the induced draft fan. Since this flue gas would not pass through an ESP, the affect on particulate discharge for the unit will need to be examined if this scenario is implemented.

If this scenario is used, at full load the cold end average temperature will be 171°F which is 12°F lower than normal operation but 32°F higher than the cold end average temperature if flue gas is extracted and not replaced with the hot air. At minimum load the cold end average temperature is 139°F which is much too low.

If the flue gas/hot air mixture could be raised in temperature to 730°F, the cold end average temperature could be maintained at 183°F. Unfortunately, to do this would require raising the temperature of the hot air to 1200°F before injecting it into the duct. This is not practical.

RECOMMENDATION

To maintain the minimum cold end average temperature required for the coal being fired in Crist 5, additional heat must be added to either the flue gas prior to entry into the air preheater, to the air prior to entry into the air preheater, or a combination of the two.

As was stated above, injecting the hot air available from the SCR Project helps the situation, but alone is not adequate. This is all that is practical to do to the flue gas. If the existing steam coils are capable, the duty of the steam coils can be increased to raise the air temperature entering the air preheater. With the hot air injection, the air inlet temperature required at full load would be 113°F. With the hot air injection, the air inlet temperature required at minimum load would be 148°F.

This scenario is dependent on steam coil capability being available. It is also dependent on the ability to discharge the flue gas from the SCR Project directly into the stack (if induced draft fan capability will not handle the additional load).

Please note that the analysis performed for this examination is based on limited operational data and will have some margin for error. The expected error, though, should not be enough to change the basic recommendation stated above. It would probably be wise to see if additional operational data is available to verify the air preheater model used and to investigate the steam coil capability of the unit.

CRIST5.DOC

Crist Unit 5 Air Preheater Performance

(flue gas extracted in front of hot side ESP, retracted after air preheater)

Specific heat air = 0.24

Specific heat gas = 0.27

Unit load (%)	25	50	75	100	Max Load	Max Load w/extract	Min Load	Min Load w/extract
Steam generation (lb/hr)	200000	400000	550000	582000				
Air entering air preheater (lb/hr)	280000	521000	673000	700000	830834	830834	614772	614772
Flue gas entering air preheater (lb/hr)	300961	561460	726142	755754	898558	726156	651422	472036
Flue gas leaving air preheater (corrected)	340000	611000	799500	832000				
Air temperature (deg F)								
entering air preheater	100	100	100	100	100	100	100	100
leaving air preheater	525	580	596	598				592
Flue gas temp (deg F)								
entering air preheater	535	605	645	650	650	650	592	592
leaving air preheater (uncorrected)	242	245	260	262				
leaving air preheater (corrected)	211	225	242	244				
C _{air} =	67200	125040	161520	168000	199400	199400	147545	147545
C _{gas} =	81259	151594	196058	204054	242611	196062	175884	129355
C _{min} =	67200	125040	161520	168000	199400	196062	147545	129355
Effectiveness =	0.977	0.950	0.910	0.905	0.850	0.860	0.930	0.920
Calculated Values:								
Flue gas leaving air preheater (deg F)					266	177	208	131
Air leaving air preheater (deg F)					568	565	558	505
Cold end average temp (deg F)	171	173	180	181	183	139	152	142

Crist Unit 5 Air Preheater Performance

(continued on front of last page)

Specific heat:

Specific heat gas

Unit load (%)

Steam generation (lb/hr)

Air entering air preheater (lb/hr)

Flue gas entering air preheater (lb/hr)

Flue gas leaving air preheater (corrected)

Air temperature (deg F)

entering air preheater

leaving air preheater

File no temp (deg f)

enierung der preheater

leaving air preheater (uncorrected)

leaving an preheater (corrected)

Cair :=

$C_{gas} =$

$$C_{min} =$$

Effectiveness

Calculated Values:

Flue gas leaving air preheater (deg F)

Air leaving air preheater (deg F)

Cold end average temp (deg F)

	0.24				0.268				Unit Load w/correct
	0.27				Max Load w/correct				Min Load
Unit load (%)	25	50	75	100	Max Load				
Steam generation (lb/hr)	200000	400000	550000	582000					
Air entering air preheater (lb/hr)	280000	521000	673000	700000	830834	830834	614772	243	177
Flue gas entering air preheater (lb/hr)	300961	561460	726142	755754	898558	858564	651422	561	560
Flue gas leaving air preheater (corrected)	340000	611000	799500	832000				171	139
Air temperature (deg F)									
entering air preheater	100	100	100	100	100	100	100	208	
leaving air preheater	525	580	596	598				558	
Flue gas temp (deg F)								154	
entering air preheater	535	605	645	650	650	642	592		
leaving air preheater (uncorrected)	242	245	260	262					
leaving air preheater (corrected)	211	225	242	244					
C _{air} =	67200	125040	161520	168000	199400	199400	147545		
C _{gas} =	81259	151594	196058	204054	242611	230095	175884		
C _{min} =	67200	125040	161520	168000	199400	199400	147545		
Effectiveness =	0.977	0.950	0.910	0.905	0.850	0.850	0.930		
Calculated Values:									
Flue gas leaving air preheater (deg F)					266	243	208		
Air leaving air preheater (deg F)					568	561	558		
Cold end average temp (deg F)	171	173	180	181	183	171	154		

Crist Unit 5 Air Preheater Performance

(hot air temperature, steam coil duty increased)

Specific heat air = 0.24

Specific heat gas = 0.27

Unit load (%)

Steam generation (lb/hr)

Air entering air preheater (lb/hr)

Flue gas entering air preheater (lb/hr)

Flue gas leaving air preheater (corrected)

Air temperature (deg F)

entering air preheater

leaving air preheater

Flue gas temp (deg F)

entering air preheater

leaving air preheater (uncorrected)

leaving air preheater (corrected)

Cair =

Cgas =

Cmin =

Effectiveness

Calculated Values

Flue gas leaving air preheater (deg F)

Air leaving air preheater (deg F)

Cold end average temp (deg F)

	25	50	75	100	Max Load	Max Load w/extract	Min Load	Min Load w/extract
Specific heat air	0.24							0.266
Specific heat gas	0.27							0.268
Unit load (%)	25	50	75	100	Max Load	Max Load w/extract	Min Load	Min Load w/extract
Steam generation (lb/hr)	200000	400000	550000	582000				
Air entering air preheater (lb/hr)	280000	521000	673000	700000	830834	830834	614772	614772
Flue gas entering air preheater (lb/hr)	300961	561460	726142	755754	898558	838564	651422	611228
Flue gas leaving air preheater (corrected)	340000	611000	799500	832000				
Air temperature (deg F)								
entering air preheater	100	100	100	100	100	113	100	148
leaving air preheater	525	580	596	598				
Flue gas temp (deg F)								
entering air preheater	535	605	645	650	650	642	592	595
leaving air preheater (uncorrected)	242	245	260	262				
leaving air preheater (corrected)	211	225	242	244				
Cair =	67200	125040	161520	168000	199400	199400	147545	147545
Cgas =	81259	151594	196058	204054	242611	230095	175884	162640
Cmin =	67200	125040	161520	168000	199400	199400	147545	147545
Effectiveness	0.977	0.950	0.910	0.905	0.850	0.850	0.930	0.930
Calculated Values								
Flue gas leaving air preheater (deg F)					266	252	208	218
Air leaving air preheater (deg F)					568	563	558	564
Cold end average temp (deg F)	171	173	180	181	183	183	153	183

END

**DATE
FILMED
9/04/92**