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A 12-MW-SCALE PILOT STUDY
OF
IN-DUCT SCRUBBING (IDS)
USING
A ROTARY ATOMIZER

By:

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Prepared For:

US Department of Energy
Pittsburgh Energy Technology Center
Pittsburgh, PA 15236

Under Contract No. DE-AC22-85PC 81010

Henry Pennline, Project Officer

November, 1989

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ABSTRACT

A low-cost, moderate-removal efficiency, flue gas desulfurization (FGD) technology was selected by the U.S. Department of Energy for pilot demonstration in its Acid Rain Precursor Control Technology Initiative. The process, identified as In-Duct Scrubbing (IDS), applies rotary atomizer techniques developed for lime-based spray dryer FGD while utilizing existing flue gas ductwork and particulate collectors. IDS technology is anticipated to result in a dry desulfurization process with a moderate removal efficiency (50% or greater) for high-sulfur coal-fired boilers. The critical elements for successful application are : (i) adequate mixing of sorbent droplets with flue gas for efficient reaction contact, (ii) sufficient residence time to produce a non-wetting product, and (iii) appropriate ductwork cross-sectional area to prevent deposition of wet reaction products before particle drying is complete. The ductwork in many older plants, previously modified to meet 1970 Clean Air Act requirements for particulate control, usually meet these criteria.

A 12 MW-scale IDS pilot plant was constructed at the Muskingum River Plant of the American Electric Power System. The pilot plant, which operates from a slipstream attached to the air-preheater outlet duct from the Unit 5 boiler at the Muskingum River Plant (which burns about 4% sulfur coal), is equipped with three atomizer stations to test the IDS concept in vertical and horizontal configurations. In addition, the pilot plant is equipped to test the effect of injecting IDS off-product upstream of the atomizer, on SO_2 and NO_x removals.

In both vertical and horizontal configurations, and in flue gas containing about 3800 ppmvw SO_2 , 50% SO_2 removal efficiency was achieved at a dry stoichiometric ratio (SR = moles lime/mole inlet SO_2) in the absence of dry recycle. In the presence of recycle in a horizontal station, the 50% removal is achieved at a dry SR of 1. Dry recycle also resulted in about 15% NO_x removal.

Wall wetting, attributable to large liquid/gas momentum transfer and uncertainty in the maximum droplet size generated by the rotary atomizer, was found to impede SO_2 removal. A network of wall thermocouples was used to study improvements in droplet confinement induced by gas flow devices. However, complete droplet confinement could not be achieved at the lime slurry and dilution water flow rates required for good SO_2 removal efficiency. Analytical flow modeling techniques have been used to design pilot plant duct modifications for obtaining fully non-wetting operation.

The wall wetting limitation is believed to be peculiar to only small, pilot-scale ducts. In full-scale ducts, the concern is good droplet dispersion across the entire duct cross-section, rather than droplet confinement required in pilot-scale ducts. Techniques to enhance droplet dispersion in full-scale ducts need to be developed.

Demonstration of IDS on at least a 100 MW-scale is recommended prior to commercialization of the technology.

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1.0 SUMMARY AND CONCLUSIONS

Experimental results from the IDS Pilot Plant support the following conclusions:

1. Duct injection is effective for 50 percent SO_2 removal at dry stoichiometric ratio (moles lime per mole inlet SO_2) of 1.5 in the absence of dry recycle. Dry recycle enhances both SO_2 and NO_x removal, and reduces the lime required for achieving the 50% target removal. The 50% removal is achieved in the presence of dry recycle at a dry stoichiometric ratio of 1.
2. The pilot plant operated without wall wetting with lime slurry flow rates up to half the design flow rate. The design of the pilot plant ducts was made on the basis of a cold flow model study utilizing a 100-mm atomizer at a maximum water flow rate of 1/2 gpm. The fact that the model study recommendations were found to be valid in the pilot plant up to about 1/2 the design slurry flow rate indicates that carefully scaled cold flow and analytical modeling can provide large scale design configurations.
3. A mid-duct airfoil and right and left airflaps installed just upstream of the atomizer in the horizontal duct configuration were shown to be effective in extending the maximum lime slurry flow rate without wetting onset. However, these flow devices were not effective at the high lime slurry feed rates required for effective SO_2 removal.
4. Wall wetting is specific to small, pilot-scale ducts, and is not expected to be a commercial issue. Instead, droplet/gas mixing, droplet dispersion, and droplet drying are expected to be key commercial issues. Additional work is required to define methods of enhancing dispersion of droplets produced by a rotary atomizer in large ducts.
5. A 1-second drying time has been shown to be adequate for drying of the droplets produced by GE atomizers at slurry flow rates corresponding to approach temperatures greater than 40 F. The pilot plant measurements showed the theoretical predictions for droplet evaporation to be valid.
6. Most SO_2 removal takes place in the evaporation zone corresponding to an approximately 1-second average gas residence time.

7. The ESP contributes 5 to 10 percent to the overall removal, i.e. ESP SO_2 removal efficiency = 0.05 to 0.1 times the system SO_2 removal efficiency. The ESP accounts for more than half of the removal taking place in the drift zone comprising the post-evaporation zone duct and the ESP. The ESP operation was not adversely affected by exposure to IDS service both with and without dry recycle. The ESP opacity was found to increase as the particulate concentration at the ESP inlet increased due to IDS operation. However, the ESP collection efficiency appeared to be unaffected by the increased loading from the products of reaction between the flue gas and the injected lime. Collecting plate deposits on the ESP after exposure to particulate from the IDS process were not found to be different from that observed when the ESP was exposed to only fly ash service. The ESP was found to be suitable for IDS service because: (i) it provides additional SO_2 removal and (ii) it accommodates the additional inlet loading resulting from IDS operation.
8. Dry recycle resulted in both enhanced SO_2 and NO_x removals. Although the SO_2 removal enhancement increased with increasing dry recycle injection rate, the NO_x removal enhancement was found to be relatively independent of the dry recycle feed rate. Additional work to identify the mechanism of dry recycle-promoted NO_x removal, and to optimize the process appears necessary.
9. Station 1 appeared to have operated with less severe wall wetting than Station 2. The lime utilization in Station 1 was significantly better than that in Station 2 without dry recycle. Dry recycle enhanced SO_2 removal in Station 2 and proved to be better than unenhanced removal in Station 1 in terms of lime utilization, but not by a large margin.
10. The SO_2 removal in both stations and the NO_x removal in Station 2 proved to be amenable to interpretation in terms of a modified DFGD model. The Station 1 and 2 performances are predictable using the modified model. However, applicability of the model to larger ducts having no wall wetting needs to be established.
11. Rotary atomization requires about 1 HP in electrical energy per 1000 acfm of treated flue gas. Compressed air intensive injection systems consume roughly 2 to 3 times this energy, based on a compressed air sizing criterion of 1 lb compressed air at 60 to 80 psi per 4 lb lime slurry. This gives the IDS process a significant edge in operational costs.
12. IDS technology is recommended for large-scale (> 100 MW) demonstration prior to commercialization.

2.0 PLANNING

Following the announcement of a Department of Energy (DOE) Acid Rain Pre-Cursor Award to GE Environmental Services, Inc. (GEESI) for pilot-scale investigation of the In-Duct Scrubbing (IDS) technology, a project execution strategy was formulated including plans for completing the following tasks:

1. *Signing a co-operative, cost-sharing agreement with American Electric Power (AEP), and its subsidiary, Ohio Power Company, (OPCO) for:*
  - (a) *gaining access to OPCO's 585-MW Muskingum River Unit 5 power plant for construction and operation of the pilot plant, and*
  - (b) *obtaining engineering and project co-ordination services from AEP Service Corporation (AEPSC), and operation and maintenance assistance and other services from OPCO as part of the overall cost*
2. *Construct pilot test facility:*
  - (a) *select suitable site*
  - (b) *design pilot facility*
  - (c) *procure materials*
  - (d) *erect pilot facility and assemble components*
  - (e) *shakedown of facility and instrument calibration*
3. *Conduct experimental test program:*
  - (a) *prepare test plan*
  - (b) *execute test plan*
  - (c) *analyze data*
4. *Conduct a long-term equipment reliability test:*
  - (a) *prepare test plan*
  - (b) *execute test plan*
  - (c) *analyze data*

5. *Perform dry injection testing with recycled sorbent*
  - (a) *prepare test plan*
  - (b) *execute test plan*
  - (c) *analyze data*
6. *Prepare cost estimates for a conceptual implementation of IDS technology on a 500-MW scale:*
  - (a) *prepare drawings and bill of materials for conceptual implementation of IDS*
  - (b) *prepare cost estimates*
7. *Issue final report*

The work completion plan for each task included detailed task breakdown accompanied by manpower requirements and time schedules.

The reporting structure used within GE Environmental Systems (GEESI), to administer and perform the contractual tasks described above is shown in Figure 1. The Program Manager has overall project responsibility, directly manages all experimental programs, and also interfaces with DOE. The Project Manager leads the pilot plant construction. The Lead Test Engineer provides the technical lead on the project including design guidelines, instrumentation specifications, and test specifications. The Systems Engineer provides the technical lead for integrating sub-system equipment into the pilot plant. The Systems Engineer also coordinates inputs from the Electrical, Mechanical, and Process Design groups within GEESI. In financial matters, the resources of GEESI Finance Department are readily made available to the Program Manager. The Site Construction Manager coordinates all site activities during pilot plant construction, while the Site Testing Manager leads site operations during testing activities.

An Executive Advisory Committee comprising the Vice President of Engineering, and Particulate and Process Technology Managers was formed in order to review and critique all activities relating to the project. Design reviews and technical progress reviews at critical junctures of the project have been conducted by the Advisory Committee.

On DOE's side, the Project Officer was solely responsible for monitoring, reviewing project progress, accepting work completions, and authorizing work commencements and continuations. In contractual and financial affairs, the Project Officer was assisted by the DOE Contracting Office. In technical matters, the Project Officer drew an advisory committee from in-house experts at Pittsburgh Energy Technology Center (PETC). This advisory committee was present at technical review meetings held with GEESI.

The Program Manager reported project progress to DOE through monthly reports to DOE's Project Officer.

2.1 PILOT PLANT SPECIFICATIONS

A layout of the pilot plant, which uses a slipstream of flue gas from Ohio Power Company's (OPCO's) Muskingum River Plant Unit 5 boiler, is shown in Figure 2(a). A process flow schematic is displayed in Figure 2(b). The pilot plant consists of three atomizer stations: (1) Station 1 installed in a vertical downcomer configuration (see Figure 3), (2) Station 2 installed in a horizontal duct run long enough for a 1-second gas residence time at the design average gas velocity of 3600 ft/m, and (3) Station 3 also installed in horizontal ductwork, but with 90-degree turn in the Station 2 duct at the point corresponding to a 1/2-second gas residence time (see Figure 4). The ductwork corresponding to the downcomer is cylindrical with a 50-in. diameter. All other ductwork in the plant have a 50 in. wide X 40 in. high rectangular cross-section. The 50 in. dimension comes from process design experiments and calculations performed in support of the duct design effort. Essentially, it is half the penetration expected for the largest droplet produced from a rotary atomizer of the type to be used in the pilot plant. Details of the droplet penetration calculations are given in a later section.

Station 3 was included in order to determine if the droplets will be sufficiently dry at the end of a 1/2-second residence time to make the 90-degree turn without depositing on the duct walls at the turn. Flue gas extracted from OPCO's Muskingum River Unit 5 boiler flows sequentially through the three atomizer stations, through an electrostatic precipitator (ESP) of weighted-wire design, and then through an ID-fan back to the Unit 5 host duct. The ESP was included in order to simulate the most likely coal-fired power plant retrofit situation, and to determine if an ESP of this type can withstand the additional grain loading from partially spent lime injected into the ductwork, and the humidification-induced lower gas temperature and higher flue gas moisture content, without degradation of both ESP performance and components. The ESP may be bypassed through a high-efficiency cyclone.

Gas flow devices which were shown in cold-flow model studies to be effective in improving gas flow and droplet dispersion within the duct are also installed in the pilot plant ductwork. Laboratory experiments conducted at the GE Corporate Research Laboratories (CRD) showed appreciable NO_x removal in the presence of dry spent products suspended in a simulated flue gas flow. An ash re-injection system was installed in the pilot plant in order to further investigate this spent product-induced NO_x removal.

The pilot plant is heavily instrumented to provide data with minimal manual effort. A gas analyzer provides complete flue gas analyses (CO_2 , O_2 , H_2O , SO_2 , NO , and NO_2) sequentially at 5 key sampling locations (Station 1 inlet and outlet, Station 2, Station 3 and ESP outlets). A flow venturi after the ID fan on the pilot outlet duct measures the total flue gas flow rate. Differential pressure transmitters measure the pressure drop across the venturi, ESP, and atomizer. Gas temperatures are also monitored at locations comparable to the gas sampling locations. Boundary layer gas temperatures are monitored by a 8X4 network of wall thermocouples spanning 1/2-second residence time in each station. Because of overlap, Station 2 and Station 3 thermocouples may be combined to obtain the wall temperature profile over almost the entire 1-second

Figure 1. Project organizational structure.

Figure 2(a). Pilot plant schematic (plan).

Figure 2(b). Pilot plant process flow schematic.

Figure 3. Conceptual schematic of downcomer configuration of atomizer.

Figure 4. Schematic of atomizer stations in horizontal pilot plant duct.

length of Station 2 ductwork. A 3X3 array of heavy-duty anemometer elements is used to characterize the velocity distribution in an entire duct cross-section instantaneously. Through suitable test port design, the same anemometer sensor grid could be used in Station 1 duct which have circular cross-section as well as in the Station 2 and Station 3 duct which have rectangular cross-section.

All pilot plant measurement signals together with selected Unit 5 boiler and generator signals are wired, typically through 4-20 mA current loops, to an A/D converter connected serially (RS-232C) to an AT-type Hewlett-Packard Vectra computer. Thermocouples are wired directly to the A/D converter which also provides voltages from compensating temperature elements. The A/D converter digitizes the signals and delivers the digitized information to the computer, which then performs averages, conversions to engineering units and process calculations before periodically printing the data to a line printer as well as to floppy-disk drive. The computer also provides control signals to 4 PID loops which maintain test conditions in the pilot plant. The loops control: (i) louvre damper opening to ID fan inlet to maintain required gas flow rate based on signals from flow venturi, (ii) lime slurry feed rate to atomizer to maintain required SO₂ removal efficiency or outlet SO₂ concentration, (iii) dilution water feed rate to atomizer to maintain required approach to saturation or outlet gas temperature, and (iv) atomizer rpm to maintain optimum SO₂ removal levels. The signal processing is performed with the aid of ASYST, which is a scientific language with a powerful repertoire of computational and graphic subroutines. Data disks from the field are mailed to the home office where additional data analysis is performed on a similarly equipped HP Vectra computer.

2.2 PILOT PLANT COMPONENTS

Details of the pilot plant components discussed above are provided below:

1. Rotary Atomizer

The rotary atomizer is an Anhydro Model CF-250 belt driven with a 75 HP motor. A variable frequency power supply manufactured by the Square D Company allows variation of the atomizer angular speed from 10,000 to 14,000 rpm. The atomizer shaft is supported by two bearings (upper and lower). The acceleration and temperature of each bearing is continuously monitored with the aid of a Bruel and Kjaer vibration monitor and thermocouples. The atomizer rpm is also continuously measured by means of a transducer. Power to the atomizer is cut-off if any one of the following events occurs: (i) atomizer angular speed falls below 8000 rpm, (ii) atomizer lubrication system malfunctions, (iii) atomizer bearing temperature (either upper or lower) exceeds 225 F, (iv) acceleration of either bearing exceeds 10 m/s/s, and (v) if the system outlet temperature exceeds a preset temperature. The Model CF-250 atomizer is equipped with a 250 mm atomizer wheel. A design tip speed of 540 ft/s is obtained at the 14000 rpm angular speed. Figure 5 shows a detail of the atomizer mounting in Station 1.

The procedure for re-locating the atomizer system from one station to another is given in Appendix G.

2. Station 1 Inlet Vaning

As shown in Figures 5 and 6, the atomizer is mounted on the elbow of the transition from a horizontal duct of rectangular cross-section to the cylindrical and vertical Station 1 duct. The atomizer presents an obstacle to the horizontally entering Station 1 inlet gas. Vanes shown in Figure 6 were installed in order to ensure a uniform velocity profile at the end of the right-angle turn (the inlet to Station 1). Vane separations were chosen in order maintain a uniform velocity profile entering the vertical duct after the turn.

3. Electrostatic Precipitator

A GEESI model B1,1X10(9)-24-4-4-4 1.3P weighted-wire precipitator designed for an SCA of 360 ft² at a design system inlet flow rate of 40,000 cfm at an inlet temperature of 190 F. This ESP has 10, 9-in gas passages which are 12 plates deep in the direction of gas flow. Each collecting plate is 24 ft high and 3 ft wide (in the direction of gas flow). The emitting electrodes are made of 0.105 in. diameter mild steel wire. There are 3 identical pyramidal hoppers, each spanning all gas passages in width and a 4-plate (or 12 ft) length in the direction of gas flow. The ESP has four independent fields powered by two 15 kVA and two 22 kVA transformers in conjunction with GEESI's AVCON spark control circuit boards. Because the inlet field currents are limited by the higher ash loadings on the plates belonging to these fields, the lower kVA transformers suffice for powering the two inlet fields. The transformers with the higher rating are used for powering the two outlet fields.

The design gas temperature of 190 F corresponds to atomizer operation with a 60 F approach to saturation.

4. Ash Handling System

Ash and waste product from all hoppers (two duct hoppers, 3 ESP hoppers, and 1 cyclone hopper) are conveyed to a storage silo by means of a drag chain ash conveying system. The drag chain motion is interlocked with motorized rotary valves on all hoppers. The slide gates attached to each rotary hopper is manually operated. Each rotary valve is sized for an ash removal rate of 2 ton/hr while the conveying system itself is designed for a removal rate of 5 ton/hr.

5. Ash Silo

The ash silo is cylindrical in shape having a diameter of 12 ft and height of 55 ft, for a total volume capacity of 6300 ft³. At a nominal ash density of 40 lb/ft³, the ash silo can hold about 252,000 lb of ash. This capacity corresponds to a 10-day continuous operation of the IDS system with lime. The ash silo is fitted with two conical hoppers each of base diameter of 4 ft 7 in, and cone height of 6 ft, and included angle of 60 degrees. One of these hoppers is dedicated to ash evacuation, while the other is dedicated to the ash re-injection system to be described later. Ash evacuation from the hopper is through a manually operated slide gate and a rotary valve combination placed at a convenient height

Figure 5. Atomizer mounting in vertical duct (downcomer).

Figure 6. Cross-section of atomizer with turning vanes:
(a) elevation, (b) view into gas flow direction.

5. Ash Silo (Contd...)

for a dump truck to be driven close below it. Dump trucks which remove ash from this silo are equipped with vacuum pumps. A 12-in flexible hose attached to the outlet side of the rotary valve is used for ash removal to one of these dump trucks. With rotary valve activation, the ash flows under vacuum to the truck's barrel shaped storage compartment where it is mixed with water. The waste sludge is then taken by the truck for disposal at a site authorized to receive the material, which has been classified as non-hazardous by the State of Ohio Environmental Protection Agency.

6. Ash Re-Injection System

The second hopper attached to the ash silo used for the ash re-injection system, is fitted with a manually operated slide gate valve and a variable speed rotary valve. The ash re-injection system comprises: (i) a Holmes positive displacement blower rated for a 800 cfm air flow rate at a discharge pressure of 10 psig, (ii) a Fox venturi eductor, and (iii) a pneumatically operated isolation valve and associated piping. The ash re-injection system is activated by the following operational sequence: (i) opening isolation valve, (ii) starting up blower, (iii) opening ash silo slide gate, (iv) setting speed of the rotary discharge valve to obtain the desired ash injection rate using the previously determined calibration curve.

In order to prevent ash bridging and facilitate the flow of ash in the silo, the ash silo hopper was insulated and fitted with suitably sized heaters. The heaters prevented moisture condensation due to ambient temperature changes, and consequently prevented ash agglomeration inside the silo. A schematic of the ash re-injection system is given in Figure 7.

7. Opacity Monitors

Opacity monitors were installed at the inlet and outlet of the ESP with the intent of continuously monitoring ESP performance through the continuous monitoring of both the inlet and outlet opacities, assuming that the reasonable relationships between opacity and particulate loading referred to in the literature could also be established for the pilot ESP. The optical path length for the inlet opacity monitor was made adjustable in order to accommodate the high particulate loadings expected at this location. The path length for the outlet opacity monitor was maintained at the full duct width. Both opacity monitors are identical, Model 300 Transmissometers supplied by the Thermo-Electron Corporation (TECO). Each is equipped with an optical head (including light source, detector and associated electronics) on one side of the duct, and a retro-reflector on the other side. Light from the optical head traverses the duct, is attenuated in intensity by the particulate in the gas stream, reaches the retro-reflector where it is reflected toward the optical head, is attenuated again and reaches the detector where the light intensity is measured, compared with a reference beam of unattenuated light and finally output as an opacity.

7. Opacity Monitors (Contd...)

Through correlations of the opacity and the particulate loadings obtained from EPA sampling techniques, it is, in principle, possible to continuously monitor the ESP efficiency by continuously monitoring the inlet and outlet opacities. In this way the effect of lime injection upstream of the ESP on the performance of the ESP could be monitored continuously.

8. Gas Analyzer

A five-point extractive gas analysis system, also supplied by TECO, was used in the pilot plant. Gas from each of five locations (system inlet, Station 1 outlet, Station 2 outlet, Station 3 outlet or ESP inlet, and ESP or system outlet) is alternately extracted through heated and insulated sampling lines and delivered to the gas analysis system. The gas analysis system comprises a sample diluter, a sample dehydrator, and instruments to measure the concentration of SO_2 , CO_2 , NO , NO_2 , and O_2 . The diluter precisely mixes the gas sample with instrument air to maintain a fixed dilution ratio of 1 to 100. This mixing precision is achieved through the use of fine capillary tubes and pressure regulation. The diluted sample then simultaneously passes through the SO_2 , NO_x , and CO_2 analyzers. The O_2 analyzer receives an undiluted sample directly from the sample line. The gas analysis system operated in this way yields the molar flue gas composition in wet mode (i.e., including moisture in the flue gas). The gas analyzer has the facility to alternately pass the sample gas through a Perma-Pure dryer (sample dehydrator). The Perma-Pure dryer operates with the aid of capillaries made from a hydrophobic membrane material (a variation of Teflon®). When moisture laden gas is passed on the inside of the capillaries, and dry gas passed on the outside, the moisture from the flue gas sample selectively passes through the hydrophobic membrane to be entrained in the dry gas flow, leaving the sample gas free of moisture. When the dehydrated gas sample is diluted and analyzed, the flue gas composition in dry mode is obtained. The flue gas moisture concentration is obtained by comparison of the SO_2 (or other gas) concentration in wet and dry modes. The dry mode flue gas concentrations are used to calculate the efficiency of SO_2 removal since the dry gas flow rate in the system remains constant, even though the total gas flow rate changes with humidification. During air flow measurements to be described later, the air in-leakage into the IDS system was found to be negligible. As a result of this determination, no corrections to the measured flue gas concentrations attributable to air in-leakage was included in the analyses of results.

The measurement techniques used in the Gas Analysis System are shown in the following table. During pilot plant operation, the gas analyzer needed careful attention and preventative maintenance. Routine cleaning of tubings, capillaries and diaphragm pump heads were needed on a regular basis. Sample flue gas from each location was drawn through in-duct sintered metal filters.

ANALYZER	MEASUREMENT TECHNIQUE
SO ₂	Chemiluminescence induced by pulsed UV source
NO _x	Fluorescence from reaction between NO and O ₃ . NO ₂ is measured by same technique after catalytic reduction to NO
CO ₂	Infra-red absorption
O ₂	Electro-chemical cell of ceramic zirconium stabilized yttria
H ₂ O	By comparison of wet and dry SO ₂ concentrations
N ₂	By Difference

These filters needed to be routinely cleaned also. Daily calibrations of the gas analysis instruments were performed with the aid of bottled span gas and instrument air. The moisture analysis was checked against measurement of the wet-bulb temperature using a wetted thermocouple.

9. Lime Slaker

A detention-type slaker designed and supplied by Portec was installed at the pilot plant. Metered quantities of soft-burned, high-calcium, pebble lime falls into a reaction tank through which water is flowing, also at a controlled rate. The lime feed rate and water flow rate are determined by the solids fraction desired in the slaked lime and the slaking temperature. The lime and water, after an average detention time in the reaction tank determined by the reaction tank volume and water flow rate, emerge from the reaction tank as slaked lime and flow into a 10,000 gal slaked lime storage tank. The solids fraction in the slaked lime product was determined by measuring its specific gravity. The available lime in the slaked lime was determined using a procedure prescribed by EPRI.

Operating procedure for the lime slaker is given in Appendix H.

10. Wall Thermocouples

Four wall thermocouples for each duct cross-section (including the cross-section containing the atomizer) at 1.22m (4-ft) intervals are used. In the case of the cylindrical duct used in Station 1, the wall thermocouples in a given cross-section are mounted at the ends of two diameters intersecting at right angles. One of these diameters is chosen to be along the direction of gas flow (north-south direction, with the gas flow entering Station towards north). The second diameter is then along the east-west line. Figure 8 illustrates the wall thermocouple placement in Station 1. In the case of Station 2 and Station 3 ducts, which have rectangular cross-sections, one wall thermocouple is centrally mounted on each of the four sides of a duct cross-section. Figure 9 clarifies the wall thermocouple locations in the horizontal configurations.

10. Wall Thermocouples (Contd...)

Each wall temperature probe consists of a thermocouple welded to the center of a 1/2-in X 1/2-in piece of metal. This probe is aligned so that the normal to the 1/2 in. by 1/2 in. metal piece is normal to the direction of gas flow, and placed so that the center of the probe is no more than an inch from the duct wall. In this way, the wall temperature probes intercept the flue gas flow along the boundary layer.

11. In-Situ Velocity Probes

Heavy-duty hot-wire anemometer probes developed by the Kurz Company were used to simultaneously measure the gas velocity in a 3X3 grid spanning a duct cross-section. The Kurz anemometer system was rendered capable of operating in a flue gas environment through increased thickness of the hot-wire probe, maintenance of the hot-wire temperature at only 100 F above the gas temperature, and through the use of advanced electronic signal processing. Three probes, each having 3 sensing elements, as shown in Figure 10, were custom fabricated by Kurz for use at the IDS pilot plant. For each atomizer station, test ports were located at the 0-, 30- and 60-ft locations. Figures 8 and 9 also show typical test ports which allowed the same probes to be used in the vertical and horizontal stations.

The data acquisition system allowed nearly simultaneous sampling of the velocity from all nine probes or obtaining rapid velocity time data from any one probe. Both modes were used at the pilot plant.

12. Programmable Logic Controller

A GE Series One Programmable Logic Controller (PLC) was used to monitor permissives and implement the required safety procedures. A listing of the permissives is provided in Table 1. The PLC was also used to time the sample sequencing in the gas analyzer.

13. Data Acquisition and Process Control System

The Data Acquisition and Process Control System (DAPCS) comprises a Hewlett-Packard (HP) Model 3497A data-logger with associated A/D and D/A conversion cards, an IBM AT-compatible HP-Vectra micro-computer, three Foxboro Series 760 process controllers with capability for remote (computer driven) set-points, and an interface to the variable frequency atomizer drive which also allows remote set-point of the atomizer angular speed.. The data-logger acts as an analog-to-digital (A/D) and digital-to-analog (D/A) interface between the analog signals to and from the pilot plant, and the Vectra computer. This interface has two components: a control interface and a remote interface. The remote interface is located in the Station 2 atomizer housing area. Its close proximity to several pilot plant measuring instruments including the wall thermocouples, minimizes wiring lengths. The control interface is located in the control room together with the Vectra computer, the

Figure 8. Station 1 wall thermo-couple placement.

Figure 9. Station 2 and 3 wall thermo-couple placement.

Figure 10. Ruggedized hot-wire anemometer probe by Kurz Instruments.

Figure 11. Data Acquisition and Process Control System schematic.

13. Data Acquisition and Process Control System (Contd...)

motor control center, and the gas analysis system. The control and remote interfaces are connected through a multi-conductor cable. Figure 11 describes the inter-connection between pilot plant signals, the HP control and remote interfaces. Signals from the pilot plant instruments are transmitted through 4-20 mA current loop to the interface, where it is intercepted as a voltage drop across a standard resistor (usually 125 ohm). Thermocouples are wired directly to the interface. Solid state temperature sensing devices in the A/D card provide signals proportional to the thermocouple compensating temperature. The control datalogger is connected to the Vectra computer through an RS232-C communication link. Control commands for various A/D or D/A operations such as analog read, and analog send are issued as ASCII character strings from the Vectra through the serial link (RS-232-C) to the control interface, where it is decoded and executed. Any data resulting from these commands are transmitted back to the Vectra, again as character sequences. These data strings are decoded in the Vectra, assembled and related to the process. These process parameters are printed on the line printer and stored in magnetic floppy discs at a user specified sampling rate. Data from the floppy discs may be recovered for off line processing and plotting.

Four process control loops are also provided in this system. These loops control: (i) dilution water control valve operation to maintain either a fixed dilution water flow rate or a fixed outlet temperature, (ii) lime slurry control valve to maintain either a fixed lime slurry flow rate or a specified dry stoichiometric ratio, (iii) ID fan inlet louvre damper operation to maintain a specified gas flow rate at the venturi, and (iv) the atomizer variable speed controller to maintain a specified atomizer rpm. The PID (proportional-integral-derivative)-based process control of the first three loops is performed by the Foxboro controllers. The same functions for the fourth loop is performed through control circuitry in the variable frequency drive. All four controllers have the capability of having their set-points controlled from the Vectra computer. Computer-directed process control is provided through this remote set-point feature. In general any process control strategy can be implemented. However, the primary incentive for implementing computer controlled process was for providing load following capability during long-term pilot testing. During parametric testing, however, only those control functions listed at the beginning of the chapter were implemented. Computer-controlled or manually controlled modes may be invoked by the user at any time through one of the Vectra's function keys.

Data Acquisition System details pertaining to channel assignments, calibrations, and software structure are provided in Appendices E, and F.

14. Airfoil

Devices for mounting and adjusting a 24 in-wide airfoil were installed upstream of Station 2 and Station 3 atomizer locations. When gas flows past an airfoil of finite width and configured for lift, the pressure difference between the top and bottom of airfoil sides induces the formation of a double vortex at the sides of the airfoil. The dual vortex was shown in model studies to promote droplet/gas mixing and droplet dispersion. The position and angle of the airfoil are adjustable for optimizing droplet dispersion provided by the airfoil. Figure 12 shows a cross-section of the airfoil and its orientational parameters.

15. Airflaps

In addition to the airfoil position to intercept the gas flowing in the core of the duct, two smaller vertical airfoils with adjustable angle (with respect to the direction of flow) were installed upstream of the Station 2 atomizer location and positioned so as to preferentially modify the gas flow field near the two vertical walls of the duct. The objective for installing these flaps was to provide a means of diverting droplet-laden gas flow away from the vertical walls and toward the core of the duct. Figure 13 displays the size, shape, and location of the airflaps in relation to the Station 2 atomizer position.

2.3 PILOT PLANT CONSTRUCTION

The design, procurement and erection of the pilot facility was managed by the Project Manager. The erection task was supervised by the Site Construction Manager. The Project Manager coordinated the conveyance of raw and fabricated material from vendors and from the GEESI metal fabrication shop to the site. The Site Manager coordinated the hiring of craft labor having the mix of specialty skills matching erection demands. The Project Manager monitored the progress of construction activities on site, through site visits and weekly site progress reports issued by the Site Manager. The Project Manager also issued progress reports and budgetary reports to be included in the monthly reports to the DOE.

2.4 PILOT PLANT SHAKEDOWN

The following preliminary sub-system tasks were performed prior to routinely operating the pilot plant:

1. Checking out electrical wiring from Motor Control Center (MCC) to each sub-system such as process water pumps, atomizer variable frequency drive (VFD), lime slaker, ash conveying system.
2. Delineating permissives and safety trips for these sub-systems from the PID diagram, and checking out the operation of these permissives, e.g. lube oil malfunction, low process water pressure, and low atomizer rpm trip out atomizer. A complete listing of the electrical permissives governing pilot plant operation is shown in Table 1. For reference, Piping and Instrumentation Diagrams (P&ID's) for the pilot plant are included in Appendix I.
3. Checking out pressure and electrical connections to solenoid valves on instrument air lines leading to process controllers.
4. Checking out instrumentation wiring and wiring to data acquisition system.
6. Verifying response of process controllers to simulated control signals and adjustment of controller sweep amplitudes to suit the expected range of control signals.

Figure 12. Airfoil cross-section and placement in horizontal duct.

Figure 13. Airflap cross-section and placement in horizontal duct.

TABLE 1. IDS PILOT PLANT SYSTEM PERMISSIVES

EQUIPMENT				PERMISSIVE			
ITEM	DESCRIPTION	TAG #	PLC OUTPUT	DESCRIPTION	TAG #	PLC INPUT	STATUS
1.	Lime Slurry Sol.	FY-104B	066	Atomizer Speed	SSL-107	720	Off
				Outlet Temp.	TSL-114	751	Off
2.	Process Water Pump A	ME-301A	032	S A M E A S I T E M N U M B E R	1		
3.	Process Water Pump B	ME-301B	033	S A M E A S I T E M N U M B E R	1		
4.	Process Water Sol.	TY-114B	067	S A M E A S I T E M N U M B E R	1		
5.	Atomizer	ME-105	010	Lube Oil System	(On)	752	On
				Lube Oil System	(On for 15 min.)	C601	On
				Lube Oil System	Malfunction	723	Off
				Bearing Temp.	TSHH-108	754	Off
				Bearing Vibration	XSHH-109	753	Off
				Atomizer Speed	SSL-017	071	Off
				(with 45 Sec. Override)			
6.	Collecting Conveyor	ME-707	020	Ash Silo Level	LSH-707	731	Off
7.	Duct Conveyor	ME-710	022	Ash Silo Level	LSH-707	731	Off
				Collecting Conveyor	SSL-708	732	On
				(ME-707)			
8.	Precip. Conveyor	ME-714	023	Ash Silo Level	LSH-707	731	Off
				Collecting Conveyor	SSL-708	732	On
				(ME-707)			
9.	Cyclone Feeder	ME-711	021	Collecting Conveyor	SSL-708	732	On
				(ME-707)			
10.	Precip. Feeder	ME-719	011	Precip. Conveyor	SSL-715	734	On
				(ME-714)			
11.	Precip. Feeder	ME-720	012	Precip. Conveyor	SSL-715	734	On
				(ME-714)			
12.	Precip. Feeder	ME-721	013	Precip. Conveyor	SSL-715	734	On
				(ME-714)			
13.	Precip. Feeder	ME-723	030	Duct Conveyor	SSL-709	750	On
				(ME-710)			
14.	Precip. Feeder	ME-724	031	Duct Conveyor	SSL-709	750	On
				(ME-710)			
15.	Ash Silo Feeder	ME-703	041	Eductor Inlet Pressure	PSL-703	000	Off
16.	Eductor Blower	ME-700	040	Eductor Inlet Pressure	PSH-700	757	Off

7. *Installing HP-Vectra computer system.*
8. *Verifying serial (RS-232) communication between computer and data acquisition system.*
9. *Writing software device drivers for communicating between computer and data acquisition system in the ASYST language.*
10. *Developing ASYST software for (i) periodic acquisition, recording (on floppy disk) and printing of pilot plant data and derived parameters, (ii) computer based process control, (iii) developing velocity profiles from the 3X3 Kurz velocity probe grid, (iv) analysis of recorded plant data. A summary of the various ASYST software routines used for controlling the pilot plant is included in Appendix B.*
11. *Installing spindle and wheel in atomizer, and performing a 3-hr atomizer test run to checkout bearing alignment, bearing cooling, bearing vibration, bearing lubrication, and rpm variability with the Variable Frequency Drive (VFD). Analysis of the results of this test is presented below.*
12. *Activating ash evacuation system and adjusting drag chain alignment.*
13. *Verifying alignment and balance of ID fan.*
14. *Verifying all damper operations including the louvre damper used for maintaining gas flow.*
15. *Setting up laboratory equipment for the following lime-specific analytical measurements: (i) slaked lime slurry solids fraction, and (ii) available lime fraction in the lime slurry.*
16. *Checking-out electrical wiring and plumbing in lime slaker and checking out slaker operation by slaking a single batch of lime, and verifying consistency of the slaked lime.*
17. *Checking out the electrostatic precipitator internals, and controls. Bowed collecting plates were removed and the spark control circuits were optimized.*
18. *Calibrating all pressure transmitters, gas and liquid flow meters. The calibration methods and results are discussed in detail in a later section.*
19. *Programmable logic controller (PLC) operation was verified. The PLC monitors permissive conditions and executes the resultant trip out commands. The verification consisted of simulating trip conditions with a signal generator, and observing if the trip-outs do actually occur.*

20. Checking out operation of the multi-point, gas analyzer. This required checking out the sample sequencer as well as the gas analysis instruments. Plumbing leaks in the sequencer were fixed. The sequencer was also found to contain defective flow meters which obstructed gas flow. Replacement of these flow meters restored the sequencer operation. The CO₂ analyzer was found to be defective and was returned to the vendor for repairs. The repaired instrument as well as the other gas analyzer instruments functioned satisfactorily.
21. Adding the program for controlling the timing of the sampling sequencer in the gas analyzer using the PLC.
22. Installing and calibrating opacity meters at the inlet and outlet of the ESP.
23. Checking out pilot plant system operation with ambient air flow. The ID fan operability, instrumentation response, data acquisition system response, and gas flow control and atomizer rpm control without liquid feed were verified using ambient air.
24. Checking out pilot plant system operation with hot gas drawn from the host plant (Muskingum River Unit 5). This exercise allowed additionally to verify all process control functions at typical conditions: (i) gas flow control, (ii) atomizer rpm control with liquid feed to the atomizer, (iii) dilution water flow control to maintain a pre-set flow rate, and (iv) lime slurry flow control to maintain a pre-set flow rate. The last control function was tested with water rather than with lime. In automatic, computer controlled mode, the dilution water feed could be controlled to maintain a pre-set outlet gas temperature, and the lime slurry feed rate could be controlled to maintain a pre-set dry stoichiometric ratio

2.5 ATOMIZER START-UP

Introduction

The atomizer at the IDS pilot plant was started up during the week of 2/9/87, by J. Lundergaard of APV Anhydro A/S, Copenhagen, Denmark and D. Lapp of GEESI. The start-up comprised: (i) examination of the atomizer spindle, (ii) insertion and alignment of the spindle, (iii) attachment of the atomizer wheel, (iv) initial tensioning of the drive belt, (v) initial running of the atomizer for a one hour period, (vi) re-tensioning of the drive belt, and (vii) running the atomizer for a four-hour period during which the bearing accelerations and temperatures were monitored through the IDS Data Acquisition System and through direct readout.

Atomizer Instrument Calibration

Temperature

The bearing temperatures were deduced from the reference junction compensated thermoelectric emf of chromel-alumel (Type J) thermocouples used as the temperature sensors. The thermoelectric emf from a thermocouple from a specific bimetallic pair is a function only of the absolute hot and cold junction temperature, and thus is a thermodynamic potential function. If $[E(T) - E(T_r)]$ is the thermoelectric emf for a thermocouple having its hot junction at T K and cold junction at a standard reference temperature, T_r K, and further if $E_r(T)$ is the thermoelectric emf during measurements of the temperature T when the cold (reference) junction temperature is T_r , then,

$$E_r(T) = E(T) - E(T_r) \quad -(1)-$$

or
$$E_r(T) = [E(T) - E(T_o)] - [E(T_r) - E(T_o)] \quad -(2)-$$

which yields the standard thermoelectric function:

$$[E(T) - E(T_o)] = E_r(T) + [E(T_r) - E(T_o)] \quad -(3)-$$

Equation (3) states that the thermoelectric emf referred to a standard reference junction temperature (i.e. thermocouple table values which are usually referred to a 32 F cold junction) may be obtained from the emf measured with respect to a different reference temperature, T_r , by adding to it the standard thermoelectric emf corresponding to the temperature T_r .

The standard thermoelectric emf is ideally an exact quadratic function in T . i.e.,

$$[E(T) - E(T_o)] = aT^2 + bT + c \quad -(4)-$$

where a , b , and c are constants for a given thermocouple and reference temperature, and are available in the literature for various thermocouples. Equation (4) yields the standard emf for a given hot junction temperature. Temperature determination through Equation (3) requires the inverse relationship of the hot junction temperature for a given emf. This is obtained by solving the quadratic equation derived from Equation (4):

$$aT^2 + bT + c - [E(T) - E(T_o)] = 0 \quad -(5)-$$

which is in principle exact, and the preferred method of inversion over the common practice of inversion through fitting the temperature T to a polynomial of the emf.

Obtaining the temperature T through Equation (3) requires knowledge of the reference junction T_r . In practice this is accomplished by measuring the reference temperature through a solid-state (non-thermocouple) device.

Acceleration

The bearing acceleration is measured with a Bruel and Kjaer acceleration monitor which is internally calibrated through an electronic calibration signal.

Angular Speed

As with the acceleration, the atomizer angular speed (RPM) is calibrated through a synchronizing signal internal to the rpm transmitter.

Theory

The time variation of the atomizer bearing temperature is amenable to the following relatively simple analysis, based on a constant frictional heat production rate in the bearings, and cooling of the bearings governed by convective heat transfer theory. The differential equation governing the thermal energy exchange between the atomizer bearings and its surroundings may be written as:

$$a \, dT = [b - c(T - T_0)] \, dt \quad \text{-(6)-}$$

where

a = effective mass times the specific heat of the bearing

dT = change in bearing temperature in a time increment of dt

b = constant rate of frictional heat production in the bearing

c = effective surface area times the emissivity of the bearing

T = bearing temperature at time t

T_0 = temperature of air surrounding the bearing, and

dt = time increment

The solution to Equation (1) may be written as:

$$T = T_s - (T_s - T_0) \exp(-t/t_0) \quad \text{-(7)-}$$

where

T = bearing temperature at time t

T_s = steady state bearing temperature

T_0 = temperature of air surrounding the bearing, and

t_0 = time constant characteristic of bearing heating to its steady state temperature

The constants a , b , and c in Equation (1), and the constants T_s and t_0 are related by the following expressions:

$$T_s - T_0 = b/c = B \quad \text{-(8)-}$$

$$t_0 = a/c = A \quad \text{-(9)-}$$

Using the constants defined in Equations (8) and (9), Equation (7) can be re-written as:

$$T = (T_0 + B) - B \exp[-t/A] \quad \text{-(10)-}$$

This form for the atomizer bearing temperature at time, t , shows that the second term is constant with respect to ambient temperature, T_0 . If the constants A and B are known from analysis of the atomizer temperature vs. time history for one value of T_0 , the atomizer bearing temperature development for another value of T_0 may be calculated from Equation (10).

Data:

The upper and lower bearing temperatures, upper and lower bearing accelerations, and the atomizer angular speed were monitored during the entire four-hour period at one-minute intervals, and are presented in Figures 14, 15, and 16. Each data point is an average of three successive readings at 20 msec intervals.

Discussions

Bearing Temperatures

Figure 14 shows the atomizer upper and lower bearing temperatures interpreted according to Equation (7). The analysis yields the following best fits to Equation (7):

$$\text{Upper Bearings: } T_1 = 177.38 - 74.78 \exp(-t/21.19) \quad \text{-(11)-}$$

$$\text{Lower Bearings: } T_2 = 147.39 - 83.43 \exp(-t/36.25) \quad \text{-(12)-}$$

Equation (11) yields a value of 177.38 F for the steady state temperature of the upper bearing, and a value of 103.60 F for the temperature of the air surrounding upper bearing. Similarly, Equation (12) yields values of 147.39 F and 64.96 F for the steady state and surrounding air temperatures for the lower bearing. Equations (11) and (12) also indicate that the time constant for reaching steady state temperatures is longer for the lower bearing (36.25 min) compared with 21.19 min for the upper bearing. The above analysis indicates that the upper bearing, by virtue of being close to the drive pulley produces more frictional heat than the lower bearing, and as a result heats up faster. The upper bearing also appears to be surrounded by hotter air than the lower bearing.

Equations (11) and (12) are representative of bearing temperature development on a typical winter day. Equation (10) may be used to predict the bearing temperature development on a hot summer day, as:

$$\text{Upper Bearings: } T1 = 227.38 - 74.78 \exp(-t/21.19) \quad -(13)-$$

$$\text{Lower Bearings: } T2 = 197.39 - 83.43 \exp(-t/36.25) \quad -(14)-$$

where it is assumed that the average summer ambient temperature is 50 F higher than that in winter. Figure 17 compares the model prediction for the bearing temperature development in summer with that measured for winter. The predicted steady state upper and lower bearing temperatures for summer operation are in the neighborhood of 225 F and 200 F compared with the measured 174 F and 147 F steady state temperatures representative of winter operation. The higher bearing temperatures predicted for summer operation are of concern. The atomizer manufacturer, Anhydro, recommends maintaining both bearing temperatures below 200 F. The above analysis indicates that external cooling may be required to maintain the recommended temperatures in the summer months.

External cooling of atomizer bearings was found necessary, as predicted by the above analyses, for safe operation of the atomizer during the summer months. The external cooling was achieved by flowing instrumentation air past the bearing through an auxiliary port in the atomizer. The air flow rate was adjusted until the steady state bearing temperatures were below the recommended 200 F upper limit.

The above analyses for bearing temperature variation, if performed routinely, may be used as a diagnostic tool for detecting bearing failure onset ahead of complete bearing failure.

Bearing Acceleration

Figure 15 displays the time variation of the upper and lower bearing acceleration. The lower bearing acceleration appears higher than that of the upper bearing during the period of atomizer start-up. During the steady state idling of the atomizer wheel, the upper bearing acceleration becomes larger. The higher acceleration in the lower bearing during the initial start-up period may indicate too rapid a rate of increase of the atomizer angular speed during start-up. The acceleration monitor may be used to moderate the rate of increase of the atomizer during start-up so as to always maintain the lower bearing acceleration at a value smaller than that of the upper bearing.

Atomizer Angular Speed

Figure 16 displays the time variation of the atomizer rpm during the four-hour start-up run. This figure displays the stability of the Variable Speed Drive Control System in maintaining and varying the atomizer angular speed.

Figure 14. Time variation of atomizer bearing temperatures during start-up tests.

Figure 15. Time variation of atomizer bearing accelerations during start-up tests.

Figure 16. Time variation of atomizer angular speed during start-up tests.

Figure 17. Theoretical prediction for atomizer bearing temperature variation during start-up in summer months.

Conclusion

Atomizer-related data gathered during the four-hour atomizer start-up operation indicates (i) predictable behavior of the atomizer bearing temperatures, (ii) bearing temperatures predicted for summer operation are likely to exceed Anhydro's safety guidelines; external cooling may be required to be within the Anhydro guidelines, (iii) stable operation of the Variable Frequency Drive Control System, and (iv) expected atomizer bearing accelerations except somewhat anomalous behavior during the initial period when the atomizer wheel speed is changing. The analysis of the results indicates a method of detecting bearing failure at its onset through analysis of the bearing temperature-time history. The analysis also indicates anomalous bearing accelerations immediately following atomizer power-on, and appears to be avoidable through controlled rate of increase of the atomizer angular speed.

2.6 INSTRUMENT CALIBRATION

Introduction

Essential pilot plant process variables relating to gas and liquid flow are monitored through electronic transducers and communicated to the Data Acquisition and Process Control System (DAPCS) through current loop transmitters. The A/D Interface to the DAPCS measures the current in each measurement loop as the voltage drop across a fixed resistor (usually 250 ohm).

Pressure & Temperature

Measurements relating to gas flow are performed through 'Rosemount' pressure transducers, while measurements of gas and liquid temperatures are performed through Type J thermocouples directly connected (without transmitters) to the A/D interface. The only exception to the directly connected thermocouple technique is the measurement of the Station 3 outlet (ESP inlet) temperature, which is measured with a Type J thermocouple, but transmitted through current loop. The current loop is required in this case because this temperature is also a process control setpoint being input to one of the Foxboro process controllers.

Thermocouple EMF vs. Temperature Reduction Procedure

The bearing temperatures were deduced from the reference junction compensated thermoelectric emf of chromel-alumel (Type J) thermocouples used as the temperature sensors, using the procedure described above in Section 1.5.

Gas Flow Venturi

Venturi made to ASME specifications have well defined discharge coefficients (i.e., pressure drop vs. flow rate relationship). However,

because of the rectangular slipstream inlet and outlet ductwork in the IDS pilot, venturi of rectangular cross-section were designed for measurement of inlet and outlet flow rate. During initial gas flow testing it was found that assuming ASME-recommended discharge coefficients for the venturi resulted in an imbalance between inlet and outlet flows, and led to the recognition of the inapplicability of the ASME standards for the venturi of rectangular cross-section, and the need for separate calibration of each venturi in the IDS pilot plant.

The discharge coefficient for a venturi or related instrument is indicative of the extent to which the kinetic energy difference between the venturi inlet and throat sections is converted to static pressure drop. A coefficient of 1 corresponds to complete conversion, and indicates no net pressure loss in the venturi (i.e., the pressure drop between the venturi inlet and throat is completely recoverable). If k is the discharge coefficient, a fraction $(1-k)$ of the kinetic energy is dissipated as turbulence, heat, etc, leaving only a recoverable fraction k of the kinetic energy to be converted to static pressure drop. For ASME venturi at flow rates corresponding to $Re > 10^5$, $k=0.984$, while for orifices, $k=0.62$. It is the near unity discharge coefficients and the associated static pressure recoverability which make venturi such attractive fluid flow measurement devices. However, the discharge coefficients for the venturi with rectangular cross-sections deviated significantly from those which conform to ASME criteria. This inapplicability was overcome by calibrating the venturi against pitot tube velocity measurements across duct cross-sections.

The relationship between static pressure drop across the venturi and the gas flow rate is as follows:

$$v_o^2 = 334.769 DP / [k \rho (\beta^2 - 1)] \quad -(15)-$$

where v_o = gas flow velocity in ft/s

DP = the static pressure drop across venturi inlet and throat, in inches water

k = venturi discharge coefficient

β = ratio of venturi inlet cross-sectional area to venturi throat cross-sectional area

ρ = gas density in lb_m/ft^3

334.769 = constant which allows the above-specified units for DP , v_o , and ρ

Gas Flow Anemometer Grid ('Kurz' Probes)

Three anemometer probes, each containing three sensitive elements are used to measure instantaneous gas velocity over a 3X3 grid of the IDS duct cross-section. Test ports are designed such that the same probes could be used to measure the velocity in the Station 1 duct of circular

cross-section, as well as in Station 2 & 3 ducts of rectangular cross-section (see Figures 8 and 9). For each station, test ports are provided at locations corresponding to 0, 0.5 and 1 second residence times. The simultaneous measurement of velocity as a function of time has never been reported for a large duct before. The capability to perform the measurement in the pilot plant is a significant advantage since a characterization of the turbulence which will result from this capability will be important in scale-up design. The 'Kurz' probes are factory calibrated. The gas flow rates indicated by the 'Kurz' probes agreed with those indicated by the venturi within an error of less than 5%.

Dilution Water Flow Meter

The dilution water flow rate is measured with the aid of a 'Brooks' variable area rotometer. The float position in this flow meter is electronically transmitted through inductive pick-up using a pivoted helical magnetic strip.

Lime Slurry Flow Meter

The lime slurry flow rate is measured with the aid of a 'Rosemount' magnetic flow meter which measures the velocity-sensitive emf induced in electrodes placed at diametrically opposite ends in a flow tube placed in a magnetic field, as conductive fluid flows within the flow tube. Pulsed powering of the magnetic field coupled with filtering techniques are used to improve signal-to-noise ratio and minimize zero-drift.

Flue Gas Composition

The measurement of flue gas constituents is performed through an integrated Gas Analysis System assembled to GEESI specifications by Thermo Electron Corporation ('TECO'). Gas from each of five sampling locations (Station 1 inlet or System inlet, Station 1 outlet, Station 2 outlet, Station 3 outlet or ESP inlet, and ESP outlet or System outlet) is sequentially drawn through sintered metal in-duct filters and delivered to the Gas Analysis System through heated and insulated 'Teflon' sample lines. The sampled gas alternately bypasses or passes through or a 'Permapure' drier before entering a conditioning module where the sample gas is accurately mixed with dilution air, using critical flow capillary tubes, in the ratio of 1:100 by volume. The 'Permapure' drier allows alternate measurement of the flue gas composition in wet and dry modes. The diluted gas sample is simultaneously delivered to SO_2 , NO_x , and CO_2 analyzers which are sensitive to the diluted gas concentrations. Oxygen analysis is performed with a sample of the undried or dried gas bypassing the diluter.

Ambient CO_2 in the dilution air introduces a slight error in the CO_2 measurement. However, compared to the approximately 10% found in flue gas, this error is negligible. The voltage outputs from all four instruments are transmitted to the A/D Interface. The NO_x analyzer provides three outputs for NO , NO_2 , and NO_x ($\text{NO} + \text{NO}_2$) concentrations

through memory latches. Gas from each of the five sampling locations is sampled sequentially. The sample sequencing is controlled through the GEES1 Programmable Controller primarily used to monitor electrical permissives and interlocks for the entire pilot plant.

Atomizer Bearing Acceleration

The bearing acceleration is measured with a B+K acceleration monitor which is internally calibrated through an electronic calibration signal. No attempt was made to field calibrate the transmitter measuring bearing acceleration.

Atomizer Angular Speed

As with the acceleration, the atomizer angular speed (RPM) is calibrated through a synchronizing signal internal to the rpm transmitter. No attempt was made to field calibrate the transmitter measuring atomizer angular speed

Calibration Technique

All of the instruments described above are highly sensitive and capable of high accuracy. However, their useful accuracy is only as good as the accuracy of the calibration technique. Field implemented calibrations are often less accurate than those performed in the laboratory because controlled conditions for calibrations are easier to establish in the laboratory. The table below (Table 2) shows the field calibration technique used for each type of instrument and their inherent sources of error. Figure 18 shows the apparatus used to field calibrate the pressure transducers.

During calibration of each instrument, the voltage output from that instrument was continuously monitored and printed through the DAPCS. The average voltage output during the calibration period was then correlated with the measured variable. The results of the calibration are discussed below.

Results and Discussion

Table 3 below and Appendix E summarizes the relationship between the transmitter output and process variable for all the instruments at the IDS pilot plant. The constants in Table 3 were obtained by linear least-squares fits to the calibration data.

Pressure Transducers

The calibration of the differential pressure transducers used for measuring the pressure drop across the inlet and outlet gas flow venturi were repeated to assess the variation due to the error sources discussed earlier. Figures 19 and 20 illustrate the linearity between the pressure difference or absolute pressure and the transmitter output. Separate

Figure 18. Field apparatus for calibrating differential and absolute pressure transmitters in the field.

Figure 19(a). Calibration curve for differential pressure transmitter, FIT102.

Figure 19(b). Calibration curve for differential pressure transmitter, PDIT131.

Figure 19(c). Calibration curve for differential pressure transmitter, PDIT132.

Figure 19(d). Calibration curve for differential pressure transmitter, PDIT133.

Figure 19(e). Calibration curve for spare differential pressure transmitter, equipped with square root extractor.

TABLE 2. PROCESS INSTRUMENTATION FIELD CALIBRATION TECHNIQUES AND THEIR ASSOCIATED POTENTIAL ERROR SOURCES

INSTRUMENT	TECHNIQUE	ERROR SOURCES
Differential Pressure	Standardization against inclined oil-filled manometer using bellows as pressure source (See Figure 18).	1. Pressure fluctuations due to ambient temperature fluctuations affecting pressure within bellows. 2. Temperature changes affecting density of oil in manometer. 3. Leaks in pressure hose connections.
Absolute Pressure Transmitter	Standardization against inclined oil-filled manometer using bellows as pressure source	1. Ambient pressure not known accurately at transducer location. 2. Ambient pressure fluctuations. 3. Error source 1, 2, & 3 listed above for differential pressure transmitters.
Dilution Water Flow meter	Time for filling calibrated volume (barrel).	1. Barrel calibration error. 2. Error in reading liquid meniscus in large diameter polypropylene barrel. 3. Error in timing due to start and stop of filling operation. 4. Air bubbles in water source.
Lime Slurry Flow Meter	Time for filling calibrated volume (barrel).	1. Error sources 1, 2, & 3 listed above for Dilution Water Flow Meter.
Gas Analyzers	Certified calibration gas.	1. Errors in certified cal-gas concentrations. 2. Deterioration of cal-gas. 3. Piping leaks.

TABLE 2. PROCESS INSTRUMENTATION FIELD CALIBRATION TECHNIQUES AND THEIR ASSOCIATED POTENTIAL ERROR SOURCES (Continued.....)

INSTRUMENT	TECHNIQUE	ERROR SOURCES
Gas Flow Venturi	Pitot traverses at constant gas flow rate	1. Fluctuations in gas flow rate during traverses. 2. Error in Pitot tube constant. 3. Errors 2 & 3 listed above for Differential Pressure Transducers.
Velocity Anemometer Arrays ('Kurz')	Factory calibration certified calibration.	1. Error in factory
Type J Thermo- Couples	Absolute device needing no calibration	1. EMF vs. temperature prediction checked against mercury-in-glass thermometer.

calibrations of the same transmitters shown in Figures 19(a) and 19(d) indicate an error of less than 1% in calibration reproducibility. The least-squares correlation between pressure drop and voltage for these two transmitters reflect all the data from the separate calibrations.

Although the IDS Pilot Plant was originally equipped with inlet and outlet venturi, only the outlet venturi was routinely used to control the gas flow. The inlet venturi was dismantled because of flow instabilities introduced by the close proximity of this venturi to the Station 1 atomizer.

Thermocouples

The emf from each type J thermocouple was converted using the procedure described earlier. The temperatures obtained from several thermocouples using this procedure were compared with temperature measurements at the thermocouple locations using a mercury-in-glass thermometer. The thermocouple and mercury-in-glass thermometers were in agreement within 1 F.

Barrel Calibration

In preparation of the dilution water and lime slurry flow meter calibrations, the volumes corresponding to the nominal graduations of a

tared 50-gallon polypropylene barrel were measured by determining the mass of water in the barrel filled to each graduation mark. A platform scale based on levers (being a primary standard), rather than springs (a secondary standard), was used to determine the mass of water in the barrel at each graduation mark during both filling and draining of the barrel. Figure 21 shows the relationship between the nominal and actual volumes of the barrel as determined by this procedure.

Dilution Water Flow Meter

The dilution water and lime slurry flow meters were calibrated by determining the time taken to fill a fixed volume in the polypropylene barrel described above. The accuracy with which the dilution water flow meter could be calibrated was reduced by the presence of air bubbles in the plant water supply. The air bubbles tend to increase the transducer signal for a given flow rate. The noise apparent from the chart showing flow rate vs. flow meter signal (Figure 22(a)) is probably due to the presence of air bubbles.

Lime Slurry Flow Meter

In principle, the magnetic flow meter is strictly a velocity measurement device. Incompressible fluids passing through the flow meter at the same velocity will yield the same signal, regardless of their composition. Thus, for a flow meter of fixed cross-section, the flow meter output will vary only with volume flow rate (such as gpm), independent of the fluid composition. The flow rate vs. flow meter signal would be expected to be the same for water as for lime slurry of any given solids concentration. Figure 22(b) compares the calibrations of the lime slurry flow meter with water and lime slurry. A slight difference in the flow rate vs. flow meter signal is seen when all calibration points are included. However, when the calibration points corresponding to the two uppermost flow rates were omitted from the analysis, the lime slurry and water correlations are statistically indistinguishable (as seen in Figure 22(b)).

Gas Flow Venturi

In the IDS pilot plant, the inlet and outlet venturi were calibrated by performing pitot traverses of the inlet and outlet ducts, using the Kurz probe test ports, at different flow rates. Each of the variables in Equation (1) is known except for the discharge coefficient. The pitot traverse results were used to obtain the discharge coefficients for the two IDS pilot plant venturi. The discharge coefficients so obtained are plotted in Figure 23. Both venturi display similar trends for the discharge coefficient with respect to the venturi throat Reynolds number, Re , defined as:

$$Re = \rho D_h V_t / \mu ,$$

where D_h is the hydraulic diameter of the venturi throat given by:

Figure 20. Calibration curve for Absolute pressure transmitter, PIT119.

Figure 21. Volume calibration curve for barrel used in calibrating dilution water and lime slurry flow meters.

Figure 22(a). Calibration curve for dilution water flowmeter

Figure 22(b). Calibration curve for lime slurry flowmeter

Figure 23. Variation of inlet and outlet venturi discharge coefficients with Reynolds number at venturi throat.

$$D_h = 4 A_t / P_t, \text{ or}$$

$$D_h = 2 W_v H_v (W_v + H_v)$$

where:

ρ = Gas density

μ = Gas viscosity

V_t = Gas velocity at venturi throat

A_t = Venturi throat cross-sectional area

P_t = Venturi throat perimeter

W_v = Venturi throat width

H_v = Venturi throat height.

Low Reynolds numbers favor higher discharge coefficients for both flow elements. Increasing the Reynolds number appears to result in increased energy dissipation as evident from the decreasing discharge coefficients. This decreasing trend for the discharge coefficient with increasing Reynolds number appears to end at a Reynolds number of about $11 \text{ to } 12 \times 10^5$. Beyond this Reynolds number, the discharge coefficient appears to increase with increasing Reynolds number.

The lower overall discharge coefficient for the inlet venturi appears to be associated with the location of this venturi near the atomizer and the right angle turn into the Station 1 vertical duct. Flow studies in a scale model of Station 1 which included the inlet venturi showed large fluctuations of gas velocity at the venturi outlet as well as at the inlet to the vertical duct (just downstream of the atomizer and right after the turn). The higher energy dissipation arising from these velocity fluctuations appears to lower the discharge coefficient for the inlet venturi.

The inlet venturi was removed from the ductwork as a result of the flow instabilities originating from the close proximity of the inlet venturi to the Station 1 inlet. The fan inlet damper was controlled to maintain a fixed outlet gas flow rate using the output from the outlet venturi. The inlet gas flow rate was deduced from the outlet gas flow rate on the basis of the Ideal Gas Law.

Gas Analyzers

The gas analyzers were calibrated using calibration gas and zero air. The SO_2 analyzer was calibrated using two gas concentrations. The lower concentration was used to adjust zero, while the upper concentration was used to adjust the range. In the case of the NO_x and CO_2 analyzers only a single cal gas concentration was used. In this case the zero was adjusted using zero (instrument grade) air, while the range was adjusted while the

cal gas was flowing through the analyzers. The range of the oxygen analyzer was adjusted using instrumentation air. The zero for the oxygen analyzer was set in the factory.

The results of the gas analyzer calibrations are also shown in Table 3.

A summary of the calibration data is also given in Appendix E.

3.0 TECHNOLOGY

The IDS technology evolved from GE's Dry Flue Gas Desulfurization (DFGD) development programs, and is aimed at retrofit applications in coal-fired utility and industrial boilers seeking to reduce SO_2 emissions below current regulatory levels. Although the lime utilization for a given SO_2 removal is expected to be lower in the IDS process than in the conventional DFGD process, lower costs and minimal physical area requirements are expected for the IDS process.

The essential elements of an IDS system are a rotary atomizer, a lime slaker, and existing ductwork long enough to support a 1-second gas residence time (about 60 ft of duct length for an average gas velocity of 60 ft/s). Soft-burned pebble lime is slaked to yield a slaked lime suspension containing up to 25 percent solids. This slaked lime slurry is injected into the existing ductwork in the form of fine droplets with the aid of the rotary atomizer; the duct substitutes as the reacting vessel. Suitable gas flow distribution devices are used to disperse the lime slurry droplets across the duct cross-section. As SO_2 removal and droplet drying occur simultaneously, matching the drying time with the SO_2 removal rate consistent with required SO_2 levels is the main process goal. Collection of the dried reaction products along with the fly ash occurs in the existing particulate collector, invariably an electrostatic precipitator (ESP). In the case of the ESP, the increased mass loading due to reagent injection is expected to be offset by a lower gas flow rate (due to adiabatic humidification of the flue gas) as well as by beneficial particle resistivity effects in the presence of increased flue gas humidity. Because the desulfurization by-products are inert, no adverse effects to the ESP components are expected.

Process

The chemical reactions in the IDS process are the same as in the conventional DFGD process. The reactions occur between the sulfur oxides (principally sulfur dioxide) in the flue gas and the lime-containing slurry droplets while evaporation is reducing the reaction products to a dry suspended particulate. The kinetics of the SO_2 removal are generally acknowledged as proceeding along the following steps [1,2,3,4]:

TABLE 3. SUMMARY OF PROCESS INSTRUMENTATION CALIBRATION DATA

PROCESS VARIABLE	ENG. UNIT	INSTRUMENT TAG	LEAST-SQUARES RELATIONSHIP
Dilution Water Flow Rate	gpm	FIT117	1.56457 V - 1.27290
Lime Slurry Flow Rate	gpm	FIT115	4.73634 V - 4.61914
Inlet Venturi Diff. Press.	in. water	FIT102	1.33566 V - 1.34511
Outlet Venturi Diff. Press.	in. water	FIT133	1.24141 V - 1.26174
Atomizer Diff. Press.	in. water	PDIT131	0.99852 V - 1.00899
ESP Diff. Press.	in. water	PDIT132	0.49236 V - 0.48889
Spare Transducer	in. water	GEESI	$\sqrt{(0.50149 V - 0.50922)}$
Inlet Venturi Discharge Coeff.		@ 54,854 cfm @ 51,385 cfm @ 37,024 cfm @ 25,819 cfm	0.781 0.758 0.764 0.774
Outlet Venturi Discharge Coeff.		@ 55,993 cfm @ 51,679 cfm @ 37,106 cfm @ 25,375 cfm	0.810 0.804 0.836 0.873
ESP Power:			
TR, A			
Sec. Volt.	kV		20.9923 V - 20.1325
Sec. Cur.	mA		132.298 V - 125.965
TR, B			
Sec. Volt.	kV		20.7598 V - 19.7102
Sec. Cur.	mA		132.828 V - 127.141
TR, C			
Sec. Volt.	kV		19.2053 V - 19.0533
Sec. Cur.	mA		122.941 V - 123.535
TR, D			
Sec. Volt.	kV		19.9939 V - 20.2714
Sec. Cur.	mA		121.927 V - 121.467
Gas Velocity	ft/min	'Kurz' Probes	799.424 V - 10.067
SO ₂ Conc.	ppmv		1006.803 V - 20.1361
NO Conc.	ppmv		196.992 V + 4.338
NO + NO ₂ Conc.	ppmv		198.693 V + 3.9739
O ₂ Conc.	% (vol)		5.0998 V - 0.0153
CO ₂ Conc.	% (vol)		4 V

- (i) SO_2 diffusion in the gas phase to the droplet surfaces
- (ii) Dissolution of the SO_2 impacting the droplet surfaces, i.e.

- (iii) Lime dissolution, i.e.

- (iv) Chemical reaction between the dissolved SO_2 and lime species, i.e.

- (V) Product oxidation, i.e.

Gas diffusion (Step (i)), and chemical reaction (step (iv)) are generally recognized as the rate limiting steps in the kinetics of SO_2 removal; lime and SO_2 dissolution take place relatively rapidly. Most of the SO_2 removal takes place during the often called Phase II (see Figure 24), when the slurry droplet still has liquid water, and maintains its surface at the wet bulb temperature. In the preceding step (step A to B in Figure 24), or Phase I, the droplet rate of evaporation and surface temperature change until the state evaporation conditions of Phase II are reached. Phase I is usually of much shorter duration than Phase II. During Phase II (step B to C in Figure 24), lime and SO_2 dissolution can progress rapidly, unimpeded either by product deposition on the lime particles or by the high concentration of solids in the droplet which limit the water to only the interstices between particles. Phase II of evaporation continues until surface dryness is reached, and the amount of liquid water in the droplet is insufficient to maintain a constant surface temperature. When this condition occurs, Phase III (step C to D in Figure 24) of the evaporation process is said to be initiated.

Figure 24. Stages of water evaporation.

Figure 25. Horizontal duct slurry injection zone (conceptual).

During Phase III, the droplet surface temperature approaches the gas temperature. Droplet evaporation is said to be in Phase IV (step D to E) when the droplet surface temperature is essentially equal to the gas temperature and only interstitial water is being evaporated. The SO_2 removal which occurs during Phase III and Phase IV is a result of the dry reaction of flue gas SO_2 and moisture with the lime particles, and is promoted by interstitial water. The SO_2 removal taking place in the particulate control device is attributable to Phase III and Phase IV of droplet evaporation.

The IDS absorption zone consists of three parts: (1) the slurry injection zone, (2) the evaporation zone, and (3) the drift zone. The slurry injection zone for a horizontal installation is presented in Figure 25. Minor modifications to existing ductwork are usually required to physically support the vertically mounted atomizer and to enhance gas/slurry mixing dynamics. Scaled cold model studies and two-phase, three-dimensional analytical computer modeling are used to define optimum duct configurations for a specific application. The selection of rotary atomization for the slurry injection has been promoted by three advantages:

- (1) Rotary atomizers generate droplets with a significant droplet size distribution which allows droplet evaporation (and consequently, SO_2 removal) to be spread over time, hence avoiding flash evaporation. Figure 26 shows the droplet size distribution expected for the Pilot Plant's atomizer equipped with a 250-mm diameter wheel, and rotating at 12,500 rpm, based on a correlation developed from measurements of atomizer droplet size distributions.
- (2) The radial momentum from the stream of droplet injected from a rotary atomizer results in a droplet curtain, or umbrella, with superior mixing characteristics due to induced vorticity [5,6].
- (3) Rotary atomizers have demonstrated reliable operation based on experience from thousands of hours in conventional spray absorber DFGD service.

Phase I and Phase II of droplet evaporation takes place in the evaporation zone immediately downstream of the atomizer in a section of ductwork downstream of the atomizer that has no turns, transitions, or obstructions. The length of duct for the Phase I and Phase II evaporation is determined by the gas-to-slurry contact time necessary to just attain surface dryness. While the exact residence time requirement is dependent on gas temperatures, droplet size distributions, and retained moisture in the solids, investigations have shown that about 0.5 seconds should yield surface dryness for droplets injected by a rotary atomizer under typical duct conditions

Phase III and Phase IV of droplet evaporation take place in the drift zone comprising the duct work which follows the straight duct section designed for the evaporation zone, and includes the particulate collector. There are no configurational requirements or restrictions at this stage of the process when all the entrained particles have reached surface dryness. SO_2 removal continues to occur in this zone to improve lime utilization. On a practical basis, a minimum drift zone corresponding to a 0.5 to 1 second residence time is desirable. The SO_2 removal taking place in the particulate collector can be appreciable. In the case of an electrostatic precipitator, drift zone removal is promoted by the roughly 5-second residence time. In the case of a fabric filter this removal is promoted by all the flue gas flowing past the filter cake containing the surface dried solids.

Development

The major concerns recognized in the conceptual scale-up of the IDS technique were wall wetting and adequate mixing of reagent and gas in a confined ductwork. Droplet/gas mixing should take place promptly (i.e. before droplet evaporation has progressed substantially), and should result in a dispersion of droplets across the duct cross-section sufficient for effecting the required SO_2 removal, and yet without radial wall wetting. The degree of difficulty for enhancing droplet dispersion without wall wetting is a function of the duct size. Droplets injected by the rotary atomizer will penetrate radially into the duct due to the initial velocity imparted to them by the atomizer. When the duct dimensions are smaller than or comparable to the droplet penetrations, (as in pilot-scale ductwork) wall wetting effects will be difficult to minimize. On the other hand, when the duct dimensions are larger than the droplet penetrations, the area of concern shifts in the opposite direction to droplet dispersion effectiveness.

The primary focus in the IDS developmental efforts at GE has been in the area of droplet dispersion enhancement for large ducts of practical interest in commercial installations. It is generally agreed that the wall wetting issues peculiar to the small sized ducts do not seriously impact commercialization of the technology. Experiments in pilot-scale ductwork do play an important role in demonstrating the effectiveness of the process in removing SO_2 with good lime utilization.

Vertical (Downcomer) configuration

Full-scale cold flow model studies coupled with analytical two-phase, three-dimensional analytical fluid flow modeling were used to determine the optimal size of the ductwork for the IDS pilot plant. In the experimental model study, an atomizer with a 100-mm (4-in.) diameter wheel spinning at 3456 rad/s (33,000 rpm) to maintain a tip speed of 165 m/s (540 ft/s) at a water flow rate of 1.5 l/m (0.4 gpm) was mounted at the top inlet to a vertical (downcomer) section of cylindrical ductwork of diameter 4 ft (1.22 m). The inlet ductwork into the cylindrical downcomer

was not modeled. Cylindrical (rather than rectangular) geometry for the downcomer was prompted by the cylindrical symmetry of the atomizer wheel in the downcomer configuration, and by the resulting simplification of the analytical modeling of the experimental configuration. The analytical modeling was performed concurrently with the experimental program in order to provide an experimentally verifiable basis for scale-up using the analytical technique. A photograph of the droplet plume generated in the cold flow model is shown in Figure 27. Figure 28 shows the analytically predicted droplet trajectories, and Figure 29 shows the analytically predicted droplet diameter dependence of droplet penetration. The measured wetting radius of 22 in. is compared, in Figure 29, with the analytically predicted droplet trajectories. The 22 in. Penetration corresponds to a maximum droplet diameter of 95 micrometers. There is little dependence of the droplet penetration on the axial component of the gas velocity. Once deceleration is complete in the radial direction, these small droplets will follow gas streamlines and will readily respond to the turbulent fluctuations of the gas velocity.

Figure 30 displays the spatial variation of the droplet mass concentration profiles in the direction of gas flow. Only a slight droplet core remains at about 30 ft (10 m) downstream of the atomizer. This result favors a roughly 0.5-second gas residence time requirement for obtaining a dry product. The pilot plant ductwork was designed for a 1-second residence time, to allow the more complete dehydration of the off-product particles. Figure 31 shows the dissipation of the tangential velocity component imparted to the gas by the swirling droplets injected into the gas stream by the rotary atomizer. After about 12 ft (4 m), the gas essentially loses almost all of this tangential velocity component.

The measured droplet size distribution from a rotary atomizer shown in Figure 26 is consistent with a maximum droplet diameter of 95 micrometers.

The duct diameter of the IDS downcomer duct was chosen as 50 in. (1.27 m) on the basis of the experimental and theoretical model studies of the downcomer configuration. Uncertainty in this choice for the duct diameter stems from two sources : (1) from the extent of departure of the maximum droplet diameter produced in a 250-mm (10-in.) atomizer wheel operating at the 165-m/s tip speed with lime, from the 95 micrometer value obtained for water from the above described studies, and (2) from the effect of larger liquid/gas momentum ratio of 0.36 expected in the pilot plant compared with a ratio of 0.01 in the experimental model study. Figure 32 illustrates the calculated effect of atomizer liquid flow on atomizer water flow rate. An atomizer water flow rate of about 14 gpm will be required to achieve a 60 F approach at the outlet of the IDS system. The 36% momentum ratio referred to above is expected at this design water flow rate.

A higher liquid/gas momentum ratio will increase the strength of the vortex induced in the gas flow by the droplet stream ejected from the atomizer and will result in a droplet penetration larger than that calculated at low liquid flow rates. A higher maximum droplet diameter will also increase the maximum droplet penetration.

Figure 26. Size distribution for droplets produced in GE/Anhydro rotary atomizer having a tip speed of 540 ft/s.

Figure 27. Droplet plume produced by rotary atomizer in a full scale model of the downcomer configuration.

Figure 28. Predictions for droplet trajectories in downcomer scale model using the FLUENT flow modeling code.

Figure 29. FLUENT prediction for droplet size dependence of the radial droplet penetration in the downcomer scale model.

Figure 30. FLUENT prediction for the spatial variation of the droplet mass concentration in the downcomer scale model.

Figure 31. FLUENT prediction for the spatial variation of the tangential gas velocity in the downcomer scale model.

Figure 32. Liquid-to-gas momentum ratio dependence on water flow rate and atomizer angular speed.

In the Pilot Plant, the cylindrical Station 1 vertical duct was inserted into a horizontal duct of rectangular cross-section. The atomizer plane coincides with the bottom of the horizontal duct (of rectangular cross-section) and the top of the vertical (cylindrical) duct. The horizontal duct serves as the inlet to the Station 1 duct.

Horizontal Configuration

A full-scale cold model study was performed to assess wall wetting and droplet dispersion enhancement techniques using the same rotary atomizer described above. Analytical flow modeling was not performed because of the complex three-dimensional flow field in this geometry. A full-scale cold model study was performed to assess wall wetting and droplet dispersion enhancement techniques using the same rotary atomizer described above. This atomizer was ceiling mounted at the inlet to a 6-m (20-ft) long duct of rectangular cross-section. The effect of varying the orientation of the atomizer and gas flow distribution devices upstream of the atomizer on the droplet dispersion were evaluated by measuring the total moisture (liquid + vapor phase) distribution across the duct cross-section corresponding to the 0.25-s residence time using near-infra-red photometric techniques. The measured moisture distributions are depicted as axonometric plots in Figure 33. The variation in the quality of the droplet dispersion indicated in Figure 33 was induced by adjustments of the flow modification devices installed upstream of the atomizer.

If the standard deviation of the total moisture content, expressed as a mole fraction, is used to quantify the droplet dispersion, a standard deviation of zero would correspond to the ideal case of uniform droplet distribution covering the entire duct cross-sectional area. The opposite limit of an infinite standard deviation would indicate complete wall wetting and no droplets dispersed in the gas stream. In a simple model of a duct cross-sectional area having a fraction, f , of the area uniformly distributed with droplets and the remaining area devoid of droplets, the standard deviation, σ , is given by:

$$\sigma = [f/(1-f)]^{1/2} \quad \text{-(24)-}$$

Figure 34 relates the percent uniform coverage of droplets to the standard deviation as obtained from the above simple formulation. The variability of the standard deviations corresponding to several of the measured moisture distributions, also plotted in Figure 34 for comparison, indicate that the droplet dispersion is controllable through adjustments of the gas/droplet mixing devices.

While the relationship shown in Figure 34 between standard deviation and droplet areal coverage is based on a simple model, it may still be used to obtain an approximate estimate of the areal coverage to be expected in horizontal IDS configurations. An observed standard deviation of 0.23 corresponds to better than 90 percent droplet coverage. If the lime utilization is at the 70 percent level, this droplet coverage could result in a 50 percent SO_2 removal efficiency in the duct.

(a)

(b)

(c)

(d)

(Measurement Reference)

(e)

Figure 33. Measured moisture profiles in full scale model of the horizontal atomizer configuration showing improvement, a to e, by means of flow control.

Figure 34. Theoretical relationship relating droplet areal coverage to standard deviation of the moisture concentration distribution in a duct cross-section.

Figure 35. Theoretical prediction for the variation of the average gas temperature with distance downstream of the atomizer at different water flow rates through the atomizer.

Theory

Droplet Evaporation

When droplets of slurry are injected into a gas stream, the gas temperature progressively decreases as a result of the latent heat of evaporation for the droplets being extracted from the sensible thermal energy of the gas (adiabatic humidification). Exact treatment of the droplet evaporation time requires a solution to simultaneous heat and mass transfer formulations [7,8]. However, a simple formulation which yields results in close agreement with the exact formulation has the advantage of the results being expressed in closed analytical form. According to the approximate formulation [2,3,4], the evaporation of many droplets in a gas stream may be treated in terms of the simple formulation for the evaporation of a single droplet in a gas stream (when the droplet evaporation does not influence the gas conditions). The single droplet formulation gives the time-dependent droplet diameter as:

$$D_0^2 - D^2 = t/B \quad \text{---(25)---}$$

with $B = d_1 \lambda / (4 Nu k_g DT) \quad \text{---(26)---}$

where: D_0 = Droplet diameter at time $t=0$, m(ft)

$D(t)$ = Droplet diameter at time t , m(ft)

t = Time, s

B = Constant as defined in Equation (26), s/m^2 (s/ft^2)

d_1 = Density of water, kg/m^3 (lb_m/ft^3)

λ = Latent heat of vaporization of water at the adiabatic saturation temperature, T_{as} (or wet bulb temperature), J/kg (Btu/lb_m)

T_{as} = Adiabatic saturation temperature, K (R)

Nu = Nusselt number (equal to 2 when there is no relative velocity between droplet and gas)

k_g = Thermal conductivity of gas, W/m/K ($Btu/s/ft/R$)

DT = Temperature difference between the gas temperature, T_i and the droplet temperature assumed to be T_{as} .

t_0 = Evaporation time for droplet of initial diameter, D_0 , s

T_i = Initial gas temperature at time $t=0$, K (R)

T_f = Gas temperature at the end of evaporation, K (R)

Equation (25) gives the evaporation time, t_o , of a pure water droplet as:

$$t_o = B D_o^2 \quad \text{---(27)---}$$

In the case of a single droplet the temperature difference, DT is given by:

$$DT = T_g - T_{as} \quad \text{---(28)---}$$

In the case of many droplets evaporating in a gas stream which influences the gas temperature, DT is replaced by a log-temperature temperature difference given by:

$$DT = (T_i - T_f) / \ln[(T_i - T_{as}) / (T_f - T_{as})] \quad \text{---(29)---}$$

Abuaf [8] has shown that Equation (25) agrees within 10 percent of the exact formulation results for the case of many droplets in the gas stream.

Equation (25) may be coupled with the expression for thermal energy conservation to obtain the gas temperature as a function of time. Adiabatic humidification may be shown to be isenthalpic (zero total enthalpy change) process, i.e., the latent heat requirement for droplet evaporation is equal to the loss of enthalpy of the gas, and may be expressed as:

$$m_1 L [1 - (D/D_o)^3] = M_g C_g (T_i - T) \quad \text{---(30)---}$$

where:

m_1 = Rate of water injection into the gas stream, kg/s
(lb_m/s)

D = Droplet diameter at time t , m (ft)

M_g = Gas flow rate, kg-mole/s (lb-mole/s)

C_g = Specific heat of gas, assumed constant, J/kg-mole
(Btu/lb-mole)

T = Gas temperature at time t , K (R)

T_f = Gas temperature at time t_o (at end of evaporation)

All other variables in Equation (30) are as defined earlier. Combining Equations (30) and (25) yields the time dependence of the gas temperature:

$$T = T_f + (T_i - T_f) (1 - t/t_o)^{3/2} \quad \text{---(31)---}$$

where

$$T_f = T_i - [(L m_1) / (M_g C_g)] \quad \text{---(32)---}$$

and t_o is as given by Equations (26), (27), and (29).

Figure 35 illustrates the time dependence of droplet evaporation predicted by the above analysis for some typical IDS conditions. Experimental results for the time dependence of the gas temperatures near the duct walls will be compared with predictions of Equation (31) for the time dependence of the bulk gas temperature in a later section of the report.

SO₂ Removal

An analytical expression for SO₂ removal efficiency has been derived for the following idealized IDS conditions [4]:

- 1) The gas velocity is uniform within the duct (the presence of vortices, eddies, and recirculation zones is ignored),
- 2) The droplet/gas mixing is uniform, with the droplets following gas streamlines,
- 3) Most SO₂ removal takes place during Phase II of water evaporation, when droplet surfaces are maintained at the adiabatic saturation temperature,
- 4) The rate of SO₂ removal is rate limited by the chemical reaction between dissolved lime and SO₂ species,
- 5) The effect of solids in the slurry droplets on the droplet evaporation time is negligible.

Under these conditions, the simultaneous occurrence of SO₂ removal and evaporation, together with conservation of thermal energy may be formulated as follows:

$$dc/dt = k_r S c_o k_g N (\pi D^2) c \quad \text{--(33)--}$$

(Global Chemical Reaction)

$$D_o^2 = D^2 - t/B \quad \text{--(34)--}$$

(Droplet evaporation-see Equation (27))

$$B = (d_1 \lambda)/(4 Nu K DT) \quad \text{--(35)--}$$

(Evaporation time constant)

$$DT = (T_i - T_f)/\ln[(T_i - T_{as})/(T_f - T_{as})] \quad \text{--(36)--}$$

(Log-mean temperature difference characterizing droplet evaporation time constant-see Equation (29))

$$L(1-f_s) = G C_g (T_i - T_f) \quad \text{-(37)-}$$

(Thermal energy conservation at the end of droplet evaporation)

$$L = N G (D_0^3/6) \quad \text{-(38)-}$$

(Dependence of number of droplets on slurry flow rate, L)

where:

c = SO_2 molar concentration (dry basis)

t = time

k_r = chemical reaction rate constant

k_g = diffusional mass transfer coefficient

S = dry stoichiometric ratio (moles CaO per mole inlet SO_2)

c_0 = inlet SO_2 concentration

N = number of slurry droplets per unit mass of inlet gas

D = droplet diameter at time t

D_0 = droplet diameter at time zero (time at which the inlet gas passes over the atomizer)

B = evaporation time constant

d_1 = density of water

d_s = density of slurry

λ = latent heat of evaporation of water

Nu = Nusselt number based on relative velocity between gas and droplet

K = flue gas thermal conductivity

T_{1m} = log mean temperature difference characterizing droplet evaporation

T_i = flue gas inlet temperature

T_f = flue gas outlet temperature

T_{as} = flue gas adiabatic saturation temperature (wet bulb temperature)

L = atomizer slurry mass flow rate

f_s = mass fraction of solids in atomizer slurry feed

G = flue gas mass flow rate

C_g = flue gas specific heat.

Equation (33) is based on an a priori assumption that the rate of SO_2 removal at any time t is proportional to the product of the rate of mass transfer of SO_2 to the droplet surfaces, and the surface area of lime per unit mass of inlet SO_2 . The surface area per unit mass of inlet gas is proportional to the dry stoichiometric ratio, with k_r absorbing the proportionality factor. The ultimate justification for this assumption is the agreement of experimental data with the expression for SO_2 removal dependence on stoichiometric ratio, flue gas inlet, outlet, and adiabatic saturation temperatures resulting as a consequence of the assumption.

Equations (34) to (36) essentially state that the evaporation of droplets during adiabatic humidification may be treated with the expression for evaporation of a single droplet in an infinite gas stream provided the difference between the droplet and gas temperatures is replaced by the log-mean temperature difference defined by Equation (36).

Equation (37) characterizes adiabatic humidification in which the latent heat for droplet evaporation is provided by the sensible heat of the gas. Equation (39) relates the droplet volume production rate to the lime slurry flow rate.

Equations (33) to (38) may be solved for the efficiency, e , of SO_2 removal during the period of droplet evaporation, as:

$$e = 1 - \exp\{-a S \ln[(T_i - T_{as})/(T_f - T_{as})]\} \quad -(39)-$$

where:

$$a = X_c (Sh/Nu) (D/\sqrt{A}) \quad -(40)-$$

where

$$\chi_c = k_r [(1 - (D_f/D_o)^3) / [d_s(1-f_s)]] \quad -(41)-$$

χ_c is a factor involving reaction kinetic constant, atomizer droplet size, and lime slurry concentration. The constants in Equations (40) and (41) are:

k_r = reaction rate constant

c_o = initial SO_2 concentration

Sh = Sherwood number

Nu = Nusselt number

D_v = volume diffusion coefficient for SO_2 in flue gas used in evaluating Sherwood number

A = thermal diffusivity given by: $A = K/[C_p d_g]$, with

K = thermal conductivity of flue gas

C_p = specific heat of flue gas (constant pressure)

d_g = flue gas density,

D_f = final diameter of slurry droplet at the end of evaporation

D_o = initial diameter of slurry droplet (at the time of atomization)

d_s = specific gravity of atomizer slurry feed

f_s = mass fraction of solids in atomizer slurry feed

In Equation (40), D_f is non-zero because evaporation of a droplet of initial diameter, D_o , leaves behind a core of solids resulting from the reaction between SO_2 and lime particles. This solid core is assumed to be packed in a sphere of diameter D_f . An expression for D_f may be obtained under the following assumptions:

- (i) the initial diameter, D_o , of droplets produced in the atomizer is independent of lime slurry concentration. Experiments [6] have shown this assumption to be approximately valid,
- (ii) the density of the solid core, d_c , is the same as that of lime.

In this case:

$$1 - (D_f/D_o)^3 = (1-f_s)d_c/[(1-f_s)d_c + f_s] \quad -(42)-$$

since the density of lime slurry, d_s , may be related to the mass fraction of solids in the lime slurry, f_s , as:

$$d_s = d_c/[(1-f_s)d_c + f_s] \quad -(43)-$$

Equation (41) may be rewritten as

$$1 - (D_f/D_o)^3 = (1-f_s)d_s \quad -(44)-$$

Equation (40) may be rewritten using Equation (43) in a form showing no dependence of the constant a on lime slurry parameters, as:

$$a = k_r (Sh/Nu) (D_v/A) \quad -(45)-$$

Equation (45) shows that the factor, X_c , is equal to the reaction rate constant, k_r . Under the assumptions used to derive Equations (42) to (44), X_c does not appear to depend on lime slurry parameters. However, spray absorber results have shown X_c to depend on the inlet SO_2 concentration (or lime slurry concentration) [1,4]. This dependence may be attributed to effects not considered in the derivation of Equation (45). The effect of the heat of reaction between SO_2 and lime on the droplet evaporation time will increase with increasing lime slurry concentration (or inlet SO_2 concentration). Because the current interest is in formulating a IDS model applicable only for flue gas from high sulfur coal, theoretical effects of lime slurry parameters on X_c were not studied further.

The SO_2 removal performance equation (Equation (39)) may also be expressed as:

$$\ln(1-e) = - a S \ln[(T_i-T_{as})/(T_f-T_{as})] \quad -(46)-$$

The percentage efficiency in Equations (39) and (45) may be obtained from the inlet and outlet SO_2 concentrations, as:

$$e = 100 (1 - C_f/C_i) \quad -(47)-$$

where:

e = SO_2 removal efficiency across the evaporation zone

C_i = inlet molar SO_2 concentration, ppmv (dry basis)

C_f = molar SO_2 concentration at end of evaporation zone, ppmv (dry basis)

Table 4. Model Predictions for SO₂ Removal In IDS System

Parameter	How Parameter Enters Equation 1	Relationship to SO ₂ Removal	Comment
Residence Time	Does not enter equation explicitly.	None, provided residence time is long enough to allow complete evaporation.	Water flow rate and the inlet and outlet gas temperatures are held at conditions which give complete evaporation.
Atomizer Angular Speed	Does not enter equation explicitly.	None, provided droplets are of such size that they evaporate completely.	For a fixed atomizer water flow rate, the time-integrated droplet diameter is independent of the initial droplet diameter, provided complete evaporation occurs.
Gas Inlet Temperature	Enters equation explicitly as T_{s1} .	SO ₂ removal efficiency increases with increasing inlet temperature for fixed approach to saturation temperature.	The water required to reach the same approach to saturation temperature increases with increasing inlet gas temperatures. The time-integrated droplet diameter increases with increasing inlet gas temperature.
Gas Inlet Moisture Content	Enters equation indirectly through the adiabatic saturation temperature, T_{as} .	SO ₂ efficiency removal decreases with increasing inlet moisture content for fixed inlet gas temperature and approach to saturation.	For the same inlet gas temperature, the adiabatic saturation temperature increases with increasing inlet moisture content. Consequently, the water required to reach the same approach to saturation at fixed inlet gas temperature decreases with increasing inlet moisture content.
Inlet SO ₂ Concentration	Enters equation indirectly through the correction factor, X_c .	SO ₂ efficiency is removal independent of inlet SO ₂ concentration for low concentrations (<1000 ppm). SO ₂ removal efficiency decreases with inlet SO ₂ concentration at high concentrations (>1000 ppm) at fixed stoichiometry.	Water flow rate and the inlet and outlet gas temperatures are held at conditions which give complete evaporation. The droplet evaporation time decreases with increasing inlet SO ₂ concentration. For inlet SO ₂ concentrations less than about 1000 ppm, the lime rates are low such that, $X_c = 1$. At higher inlet SO ₂ concentrations, X_c decreases with increasing concentration.

The constant a is dimensionless. Table 4 discusses the dependence of the model prediction for the Phase II SO_2 removal efficiency on selected atomizer and flue gas parameters. The experimental SO_2 removal efficiencies will be compared with predictions of Equations (39) or (45) later in the report.

4.0 PILOT TEST PROGRAM

The IDS Pilot Study Program provides for a multi-task effort. For each Station, clear-water tests to screen wall-wetting conditions are followed by parametric lime tests under straight-through and recycle conditions to establish operating and SO_2 removal ranges for the process.

The clear water tests begin at the conservative conditions associated with low liquid/gas momentum ratio and proceed through steps of increasing water feed (or increasing momentum ratio). The duct wall thermocouples pin-point droplet plume contacts with the duct walls. The clear water tests also evaluate the effects on the droplet plume of water feed rate, atomizer angular speed, and gas flow rates within the parametric ranges given in Table 5.

TABLE 5. IDS PILOT PLANT OPERATING RANGES

PROCESS VARIABLE	OPERATING RANGE
Inlet Gas Volume	25,000-50,000 acfm (700-1500 m ³ /min)
Inlet Gas Temperature	275-350 F (135-177 C)
Inlet Ash Loading	0-4 gr/acf (0-9.2 g/m ³)
Lime Slurry Flow	0-7500 lb/hr (0-3400 kg/hr)
Lime Feed	0-2150 lb/hr (0-960 kg/hr)
Water Flow to Slaker	0-12 gpm (0-46 L/min)
Dilution Water Flow	0-6 gpm (0-23 L/min)
Atomizer Speed	10,000-14,000 rpm (1047-1466 rad/s)

Testing continues with lime slurry. Starting from the maximum gas velocity and atomizer speed, and covering the range of previously determined optimum liquid feed rates. In addition to wall wetting and plume characterization, SO_2 removal is measured at all the intermediate locations. Product collected at end of each test is analyzed for chemical content. The pilot precipitator's baseline performance and response to reagent addition is characterized over a range of flue gas and reagent injection conditions on the basis of the opacity at the precipitator outlet.

The Test Program then shifts to investigating gas conditions favorable to enhance NO_x removal. These tests are planned for the horizontal ductwork configuration. Dry sorbent is injected upstream of the atomizer to allow mixing prior to humidification. Tests are conducted with clear water as well as with lime slurry over a range of atomizer angular speed, approach to saturation, and gas flow rate.

Results and Discussions

Station 1

Inlet Velocity Distribution---

Velocity distributions at Station 1 inlet were measured after the inlet venturi was removed. Figure 6(b) displays the duct cross-section as viewed just upstream of the downcomer 90-degree turn, and shows the obstruction cast by the atomizer shroud to the incoming gas. Laboratory measurements have shown this to distort the gas velocity profile entering the downcomer duct. Figure 36 shows a typical velocity profile taken in the pilot plant about 10 ft upstream of the turn using a 3X3 anemometer array at an inlet gas flow rate of about 25 kacfm. All nine points in the grid were scanned simultaneously. The normalized standard deviation for this distribution of 13.6 percent is within GE standards for an acceptable degree of departure from strict uniformity. Measurements of the Station 1 inlet velocity distribution were also performed in the presence of water feed to the atomizer, in order to observe potential flow instabilities caused by the swirl created by the liquid injected into the gas stream by the atomizer. No measurable difference in the velocity distribution was induced by the atomizer flow, indicating no upstream effects attributable to the atomizer liquid flow. Based on this measurement, no effect attributable to the spinning atomizer alone (without water flow) is expected, although actual measurement were not made. The above inlet velocity profile did not change significantly at an inlet gas flow rate of 50 kacfm. Careful vaning of the turn containing the atomizer is required to minimize skewing of the downcomer inlet velocity profile. As discussed earlier, an optimum vaning configuration was defined through scaled cold-flow model studies. Figure 37 shows the downcomer inlet velocity profile measured in a cold flow scale model at the 0-second plane of the atomizer for optimal vaning of the turn. The roughly 10 percent standard deviation is viewed as indication of a satisfactory inlet profile. The 0-second velocity profile was also measured in the pilot plant using a 3X3 anemometer array. The measured profile is shown in Figure 38 for a 50 kacfm gas flow rate. The standard deviations of this measured profile is nearly the same as observed for the velocity profiles measured at Station 1 inlet, but is slightly larger than predicted by model study for the 0-second plane. The coarser grid in the measured distribution for the pilot plant (3X3 in the pilot vs. 9X7 in the model study) may partly contribute to this difference. Considering the difference in the grid resolution between the model study and pilot velocity data, the two distributions are in reasonable agreement. This agreement between the model and pilot profiles validates the concept of scaled cold model testing to simulate flow effects in larger systems.

Figure 36 Velocity profile in duct-cross-section upstream of Station 1 inlet at a gas flow rate of 25 kacfm.

Figure 37. Velocity profile in 0-second plane (just downstream of the atomizer) in scale model of Station 1, at a flow rate corresponding to 50 kacfm.

Figure 38. Velocity profile in 0-second plane of pilot plant at the design gas flow rate of 50 kacfm.

Wall Temperatures---

Effect of Atomizer Angular Speed

The effect of atomizer rpm on droplet dispersion and its wall wetting characteristics was initially investigated with water at a gas flow rate of 25,000 cfm. Wall wetting profiles were inferred from continuous measurements of temperature from the 8X4 network of thermocouples, shown in Figure 8, which span 30 ft of the cylindrical Station 1 duct. Thermocouples reading the wet-bulb temperature indicate physical wetting of the thermocouple elements, and of the duct walls in the neighborhood of these thermocouple elements. Temperatures slightly higher than the wet-bulb temperature, when not indicative of the true boundary layer gas temperatures, result from the balance between cooling by droplets impacting the thermocouple elements, and the heating by the flue gas, and therefore indicate wetting onset. Figures 39 and 40 summarize the results of tests to evaluate the effect of varying the atomizer rpm on the boundary layer temperatures with water as the feed liquid. The gas flow enters the Station 1 duct towards a northerly direction before making the downward turn into the Station 1 duct. Figure 39 shows that the wall temperatures on the south and west side of the duct to be well above the wet bulb temperature, for low water flow rates approximately equal to 1.3 gpm. indicative of nearly no wetting on these two sides of the duct. Even at these low water flow rates, however, the north and east sides show wetting within 4 ft of the atomizer. Except for this localized wetting on the north and east walls at points closest to the atomizer, the vertical duct appears free from wetting at the low water flow rate of 1.3 gpm. At this water flow rate, the effect of atomizer angular speed appears to be marginal, and provides a hint that the atomizer angular speed impact is probably through droplet to gas momentum exchange. This exchange is low at the 1.3 gpm feed rate, and hence the marginal effect of the angular speed. The effect of rpm becomes discernible as the flow rate is increase to 2.5 gpm. The wall thermocouples from every side of the vertical duct indicate the best non-wetting characteristics for the 14 krpm case. For this flow rate also , localized areas within 4 ft of the north and east sides show distinct wetting. All other areas of the duct appear free of wall wetting. The non-wetting behavior even close to the atomizer on the south and west sides of the walls is significant since it indicates that the droplets created by the atomizer do not penetrate to the wall. As described earlier in Section 2, the radius of the Station 1 duct was determined as the penetration distance of the largest droplet produced in a 100-mm atomizer spinning at 33,000 rpm or 33 krpm (to maintain a tip speed of 540 ft/s). The existence of at least some non-wetting wall regions in the plane of the atomizer validates the design premise that all atomizers having different wheel diameters but spinning at angular speeds which maintain a constant tip speed of 540 ft/s produce droplets with the same distribution, and moreover, the same largest droplet. The maximum penetration of the droplets from the model study's 100-mm atomizer wheel spinning at 33 krpm appears comparable to that for droplets from the pilot plant's 250-mm wheel spinning at 14 krpm, since both maintain a tip speed of approximately 550 ft/s. The observed wetting in the north and east sides of the duct walls is attributable to phenomena other than direct droplet penetration. Possible explanations will be discussed later in this section after reviewing all the boundary layer temperature data.

Figure 39. Effect of atomizer angular speed in the range of 10 to 14 krpm on Station 1 boundary layer temperatures at a gas inlet flow rate of 50 kacfm and water flow rate of 1.3 gpm, with no gas flow distribution device.

Figure 40. Effect of atomizer angular speed in the range of 10 to 14 krpm on Station 1 boundary layer temperatures at a gas inlet flow rate of 50 kscfm and water flow rate of 2.5 gpm, with no gas flow distribution device.

Effect of Water and Gas Flow Rates

On the basis of the experiments described above, the highest rpm available for the pilot plant atomizer was used for all future droplet plume characterizations. Figure 41 summarizes the results of experiments to investigate the effect of varying the water flow rate to the atomizer spinning at 14 krpm, the highest possible rpm, with the gas flowing at its design value of 50 kcfm. At a flow rate of 1.7 gpm, only the north side of the wall close to the plane containing the atomizer wheel shows evidence of wetting. All other wall regions appear to be free from wetting. This is slightly better non-wetting performance than seen for the 25 kcfm flow rate and nearly the same water flow rate. However, in terms of the ratio of water to gas mass flow rates, the 1.7 gpm flow rate at the 25 kcfm gas flow rate is comparable to results for double this water flow rate (3.4 gpm) at the 50 kcfm gas flow rate. At a water flow rate of 3.7 gpm (close to the 3.4 gpm discussed above), the wall wetting profiles indicate less severe wetting conditions than observed the lower water flow rate of 1.7 gpm and gas flow rate of 25 kcfm. The dissimilarity in the results for the boundary layer temperatures for the two conditions suggest that the water to gas mass flow rate ratio may not entirely characterize scale-up comparison of wall thermocouple results at different gas and liquid flow rates.

At water flow rates higher than 6.6 gpm, all sides of the wall containing the plane of the atomizer wheel show evidence of wetting. The wetting region appears to extend down about 8 ft. on all sides except for the south side where it extends down to only about 4 ft. from the plane containing the atomizer wheel. The lowest wall temperatures are obtained for the west side. All other sides show high wall temperatures beyond the wetting regions. The wetting regions are confined to about 8 ft from the atomizer on all sides except the south side. On the south side wetting is observed only up to about 4 ft from the atomizer.

The extent of wall wetting was further investigated by observing the wall temperature recovery rates after a steady state water flow rate was abruptly turned off. Figure 42 summarizes the temperature recovery data after a water flow rate of 6.6 gpm at a gas flow of 50 kcfm was suddenly turned off at time labelled -1 sec in the Figure. The numbers 1 to 8 in Figure 42 refer to the planes 1 to 8 in Figure 8. The south and east recovery data indicate that the wet bulb temperatures observed from the two thermocouples closest to the atomizer on these two sides show fast recovery rates after the water flow is turned off. These two wet bulb temperatures do not appear to originate from droplet impact on the walls but rather from fully humidified or saturated gas passing along the walls. The south and east sides therefore appear to be nearly completely free of wetting at the 6.6 gpm gas flow rate. By comparison, the recovery rates on the north and west sides are slow, and probably indicative of physical wetting. On the north side, the first thermocouple essentially indicates the inlet gas temperature, as this thermocouple is located just above the plane of the atomizer, and always sees the unhumidified inlet gas. Only the 8th thermocouple located about 32 ft from the atomizer appears to show a recovery rate comparable to those seen for the south and east sides. On

Figure 41. Effect of water flow rate on Station 1 boundary layer temperatures for an inlet gas flow of 50 kcfm and atomizer angular speed of 14 krpm, with no gas flow distribution device.

Figure 42. Station 1 boundary layer temperature recovery after a water flow rate of 6.6 gpm through the atomizer spinning at 14 krpm is suddenly turned off, with the gas flowing at 50 kacfm and no gas flow distribution device.

the west side, only the 3rd, 6th, and possibly the 5th (located 12, 24, and 20 ft downstream of the atomizer) appear to show the recovery rates characteristic of unwetted walls.

The investigation of the dispersion and wall wetting characteristics of water droplets produced in the rotary atomizer in Station 1 using the boundary layer thermocouples, lead to the following conclusions:

- (i) At low water feed rates (< 2.5 gpm), the wall wetting tendency appears to improve with increasing atomizer angular speed
- (ii) Wall wetting in the plane of the atomizer does not appear to be attributable to direct droplet penetration
- (iii) The water to gas mass ratio does not appear to entirely describe scale-up of boundary layer data with respect to liquid and gas flow rates
- (iv) With water, at all flow rates the south and east walls appear to be free of any significant wetting. The north and west sides of the duct containing the atomizer plane indicate wetting for all water flow rates. The wetting region on these two sides appears to extend to about 30 ft downstream of the atomizer. The north side recovery rate is the lowest indicating wall wetting to be the most severe on this side.

Effect of Lime Flow Rate

Figure 43 summarizes wall temperature determinations with lime at a gas flow rate of 50 kcfm and atomizer angular speed of 14 krpm. The wall temperatures with lime are significantly different from those for water when the liquid flow rates are low (about 3.8 gpm). While the water profiles indicated significant wetting on the north and west sides, the lime profile indicates nearly non-wetting behavior at this flow rate. The wall wetting occurs at lime flow rates exceeding 6.9 gpm. Figure 43 indicates depression of nearly all thermocouple readings close to the wet-bulb temperature beyond this slurry flow rate.. Temperature recovery data following a lime flow rate of 8.4 gpm, as shown in Figure 44, can be used to assess the extent of wetting. The rates of temperature recovery for the case of lime with the higher lime flow rate of 8.4 gpm are lower than for water at a flow rate of 6.6 gpm. As in the case of water, the recovery rates for the south and east sides of the duct have relatively higher than those for the north and west sides which show significant evidence for wetting up to 30 ft. downstream of the atomizer plane. The more severe wetting extent on the north and west sides of the duct in the case of lime than in the case of water may be due to the larger flow rate for lime. It is also possible that the lime coated having larger effective thermal mass, are slower to respond than the water coated thermocouples. Lime coated thermocouples may only give the appearance of slower response times due to their larger effective mass rather than to wetting severity. The wall temperature data with lime may be summarized as follows:

Figure 43. Effect of lime flow rate on Station 1 boundary layer temperatures for an inlet gas flow of 50 kacfm and atomizer angular speed of 14 krpm, with no gas flow distribution device.

Figure 44. Station 1 boundary layer temperature recovery after a time flow rate of 8.4 gpm through the atomizer spinning at 14 krpm is suddenly turned off, with the gas flowing at 50 kacfm and no gas flow distribution device.

- (i) At low liquid flow rates (of about 3.8 gpm), atomizer operation with lime appears to result in nearly non-wetting conditions, whereas wetting conditions result from using water at the same flow rate.
- (ii) At a higher water flow rate of 6.6 gpm, the south and east sides of the duct appear to be nearly completely free from wetting. However the north and west sides show significant wetting up to nearly 30 ft downstream of the atomizer. In the case of 8.4 gpm of lime, both the south and east sides appear relatively free from wetting in comparison with the north and west side, which show significant wetting. Both the north and west sides appear equally severe in the wetting extents they receive. The south side temperatures indicate slight wetting on this side also with lime at 8.4 gpm than with water at 6.6 gpm.
- (iii) Comparison of the boundary layer data for water and lime (Figure 41 and 43) indicate that lower lime flow rates favor no-wetting operation, while higher lime flow rates appears to lead to wetting conditions. Water appears to be worse than lime for low flow rates, while lime appears to be worse than water for high flow rates.

Potential Wetting Causes

As mentioned earlier, the observation of non-wetting operation for lime at low flow rates, and the observation of partial non-wetting with water at low flow rates indicates that direct droplet penetration is not the mechanism for wall wetting. Comparison of the lime and water wall temperature data and the localization of the more severe wetting to the north and west sides of the duct gives some clues. The wetting of the north side appears to be related to the gas flow field associated with the right angle turn into the vertical duct, while wetting of the west side appears to be associated with the rotation of the atomizer wheel. The transverse (toward north) component of the velocity appears to be largest for the gas entering the downcomer duct on the north and west sides. As a result, only the west side appears affected by the atomizer rotation. The vanes described in an earlier section were installed in order to ensure a uniform velocity profile of the gas entering the vertical Station 1 duct. However, the length of the vanes after the turn (see Figure 6(a)) was limited below normal design length so that the vanes would end just above the plane of the atomizer. It is likely that the curtailed vanes are insufficient to entirely eliminate a northerly velocity component to the gas after the turn. It is probably this residual northerly velocity component which causes a drift of entrained droplets toward the north wall. The counterclockwise angular momentum imparted to gas through momentum transfer from the liquid droplets ejected from the atomizer may also be used to explain the wetting of the west side of the duct walls also. Thus wetting is not directly attributable to the droplet penetration. Rather, it appears to take place through droplet entrainment by the gas and the droplet/gas mixture moving along flow streamlines,

which have a northward drift because of the incompletely vaned turn. The deposition of some droplets on the duct walls is probably induced by the high level of turbulence created by the turn as well as by the droplet/gas momentum exchange.

The differences between the wall temperature profiles obtained with lime and water may also be explained by the above mechanism, if it is assumed that the atomizer produces finer droplets with lime than with water. In this case, at the low lime flow rates, the droplets will be more confined to the gas core and will have less chance of depositing on the walls through turbulence. However, as the lime flow rate is increased, the intensity of the turbulent mixing between droplet and gas increases, consequently leading to wall wetting. In the case of water, the larger droplets created in the atomizer impact the walls even at low water rates as these droplets have already penetrated close to the wall and only need a small intensity of turbulence in order to induce their wall wetting. Once these larger droplets have impacted the walls, the smaller droplets remain in the core, decrease in size as the flow progresses, and have a smaller likelihood of depositing on the walls of the duct.

In a later section, analytical flow modeling will be used to substantiate the above arguments, and to indicate the minimum diameter duct required for completely non-wetting operation.

Droplet Evaporation Time

Figure 45 depicts average wall temperature profiles for several atomizer water feed rates. The predictions of Equation 32 for the gas temperature variation under well mixed conditions were shown in Figure 35. While the gas temperature decreases monotonically and approaches the final gas temperature, the measured wall temperatures indicate a different trend. In the boundary layer near the duct wall, the gas temperature appears to first cool suddenly close to the adiabatic saturation temperature, and then recover progressively with time to the final bulk gas temperature. The droplet evaporation time can be assessed indirectly from the wall temperature profiles. The wall temperatures approach the bulk gas outlet temperature after initially being depressed close to the adiabatic saturation temperature through turbulent mixing or diffusion of the bulk gas into the boundary layer. Once the droplet to gas mixing is complete the wall thermocouples sample the bulk gas through turbulent mixing. Because of the time lag introduced by turbulence before a given wall thermocouple samples the bulk gas, the time constant of the wall temperature profile may be regarded as an upper limit for the droplet evaporation time. The agreement between the droplet evaporation time predicted by Equation (32) and that obtained from the wall temperature profiles provides evidence in favor of the above arguments for obtaining the droplet evaporation time from the wall temperature profiles. It also provides experimental evidence in favor of the calculation for a 1/2-second evaporation time for droplets produced in the rotary atomizer with a liquid flow to maintain a 60 F approach to saturation.

Figure 45. Average Station 1 boundary layer temperatures for different water flow rate with an inlet gas flow rate of 50 kacfm and atomizer angular speed of 14 krpm.

SO₂ Removal Efficiency---

The SO₂ removal efficiencies from all the tests performed in Station 1 are summarized in Table 6 and Figure 46 to 50. Detailed measurements are contained in Appendix A. Figures 46 and 47 show the effect of gas flow rate and approach to saturation on the system SO₂ removal efficiency as a function of the dry stoichiometric ratio (SR) which is the ratio of the moles lime fed per mole inlet SO₂. Data in Figure 46 are separated into four groups: (i) 25 kcfm gas flow rate and approach temperatures in the range 40 to 55 F, (ii) 25 kcfm gas flow rate and approach temperatures higher than 55 F, (iii) 50 kcfm gas flow rate and approach temperatures in the range 40 to 55 F, (iv) 50 kcfm gas flow rate and approach temperatures higher than 55 F. Data in Figure 47 are separated to show the difference in the SO₂ removals taking place in the evaporation and drift zones. There are four data groups in Figure 47 also: (i) evaporation zone removal at approach temperatures between 40 and 55 F, (ii) evaporation zone removals at approach temperatures above 55 F, (iii) drift zone removal at approach temperatures between 40 and 55 F, and (iv) drift zone removals at approach temperatures above 55 F. The gas flow rate does not appear to have a significant impact on the SO₂ removal efficiencies, suggesting that the removal is largely determined by the liquid-to-gas mass or momentum ratios only. The approach to saturation appears to be more pronounced at stoichiometric ratios (SR's) less than 0.75 than at SR's higher than 0.75. There also appears to be a slight discontinuity in the efficiency vs. SR relationship near SR=0.75. The SO₂ removal efficiency increases with increasing SR in the range from 0 to about 0.75. However, at an SR of about 0.75, the efficiency drops almost discontinuously before increasing with increasing SR above 0.75, once again. The solids concentration in the atomizer feed is the most significant variable determining the SR. The slight discontinuity at about SR=0.75 may indicate a discontinuity in the mode of droplet production in the atomizer or droplet dispersion depending on the slurry solids fraction. In each segment (SR<0.75 and SR>0.75), the efficiency appears to be a reasonably linear function of the SR. The slope for SR<0.75 is slightly higher than that for SR>0.75. This appears to indicate that the atomizer or gas flow phenomena giving rise to the discontinuity favors low solids concentration in the atomizer feed. It is also likely that the discontinuity occurs at the atomizer flow rate corresponding to wall wetting onset.

Figure 48 shows the SO₂ removal efficiency separated into contributions from the evaporation zone (the initial 60 ft of Station 1 duct), and the combined drift (remaining pilot plant duct work including Station 2 and Station 3 ducts) and the ESP. The component efficiencies shown in Figure 48 are the individual efficiencies based on the separate removals taking place in the subsystems. At an SR of about 1.5, when the targeted 50% system removal efficiency is reached, the evaporation zone accounts for about 80% of this removal. The remaining removal is in the drift zone and the ESP. Figure 49 compares the SO₂ removal efficiencies of the drift with that of the ESP. Figure 49 shows that ESP, with its nearly 5-second residence time at the design gas flow rate, accounts for the majority of

TABLE 6. STATION 1 (VERTICAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO.	INLET FLOW RATE cfm	INLET TEMP F	OUTLET TEMP F	APP TO SAT. F	STOICH. RATIO	SO ₂ REMOVAL EFFICIENCIES, %			
						@1s (EVAP ZONE)	>1s (DRIFT ZONE)	ESP	SYSTEM
1	27115	328.5	266.4	122.4	.51	13.6		3.1	16.2
2	28149	330.1	222.7	68.6	.99	25.7	7.3	2.7	33.0
3	28983	332.8	197.6	52.7	1.14	31.4	7.3	7.9	41.4
4	29337	333.2	188.9	43.4	1.23	35.1	5.4	10.9	45.3
5	27070	327.5	231.9	76.0	.89	14.6	9.8	3.6	25.7
6	26883	334.0	258.5	74.6	.43	19.1		6.8	23.9
7	27150	331.5	243.4	52.2	.57	23.3	1.1	3.1	26.5
8	55330	336.9	245.2	65.5	.46	20.9		9.2	25.9
9	53520	337.1	222.6	52.8	.45				
10	26589	330.8	197.6	39.6	1.33	43.9	1.7	8.2	49.4
11	24947	331.2	208.6	43.2	1.05	32.6	.4	11.5	40.6
12	25519	333.4	196.3	45.4	1.09	34.4	1.6	9.8	41.8
13	49131	341.8	224.4	59.6	1.04				
14	25708	338.2	199.7	47.7	1.47	43.2	23.1		51.4
15	25815	337.6	194.0	41.9	1.53	43.9	6.9	16.9	56.6
16	25674	337.1	200.1	62.7	1.45	33.6	4.4	20.3	49.4
17	48497	340.4	202.1	52.4	.62	28.4	5.3	.5	32.5
18	48934	339.7	193.1	42.9	.69	31.3	2.1	11.1	40.2
19	48982	336.2	205.3	71.7	1.06	21.9	16.1	12.9	42.9
20	49121	329.5	193.3	46.4	1.12	29.8	1.6	15.5	41.7
21	47025	338.6	193.9	45.1	1.50	34.8	4.9	20.6	50.8
22	47615	337.7	202.9	64.9	.88	20.3		12.5	30.0
23	47990	340.3	209.0	62.1	.87	17.5	3.7	1.7	21.9
24	47690	334.9	208.5	59.4	.85	22.8		8.2	28.3
25	0				.00				
26	47084	341.2	214.1	59.6	1.39	38.1	1.0	7.8	43.5

Figure 46. Effect of inlet gas flow rate on the Station 1 system SO₂ removal efficiency.

Figure 47. Effect of approach temperature on Station 1 SO₂ removal efficiencies in the evaporation and drift zones.

Figure 48. Station 1 SO₂ removal efficiencies attributable to the evaporation, drift, and ESP zones.

Figure 49. Comparison of Station 1 SO₂ removal efficiencies in the drift and ESP zones.

Figure 50. Comparison of Station 1 SO₂ removals occurring in the evaporation, drift, and ESP zones, referred to the inlet SO₂ mass flow rate.

Figure 51. Comparison of Station 1 SO₂ removal data with DFGD model prediction in the evaporation zone and the system.

the removal taking place in the post-evaporation zone. By comparison, the removal taking place in the drift zone, which comprises roughly 120 ft of duct (or a 2-second residence time at the design flow rate), is roughly half of that taking place in the ESP. The predominance of the ESP in the post-evaporation zone SO_2 removal is an interesting phenomenon, when considering that most of the off product is removed in the inlet field of the ESP. It appears that the unreacted lime deposited on the ESP plates continue to be active. It is also conceivable that the electric field in the ESP exerts a synergistic enhancement of the SO_2 removal rate in the ESP. Figure 50 shows the contributing SO_2 removals from different parts of the IDS system separated as additive efficiencies, i.e. efficiencies based on the system inlet SO_2 mass flow rate rather than the inlet SO_2 mass flow rate entering the sub-system.. This figure shows more clearly that of the 50% removal, roughly 40% comes the evaporation zone and the remaining 10% from the remaining path in the duct and ESP. Figure 51 compares the Station 1 SO_2 removal efficiencies to the analytical expression given in Equation 31. Although the data are suggestive of the linear trend between $-\ln(1-e)$ ($=Y$ or ordinate) and $\ln[(T_i-T_{as})/(T_f-T_{as})]$ ($=X$, or abscissa), better residuals (sums of

difference of squares between observed and fitted values) are obtained for a variation of Equation (46):

$$\ln(1-e) = -a \{S \ln[(T_i-T_{as})/(T_f-T_{as})]\}^b \quad -(48)-$$

where a and b are constants. The fits shown in Figure 51 are based on Equation (48). There is no theoretical justification for Equation (48). It is used here only because it provides excellent fits to the observed Station 1 SO_2 removal data for both the evaporation zone and the system. The applicability of either Equation (47) or Equation (48) to the system also cannot be justified at the present time. However, the system SO_2 removals fit Equation (48) better than the evaporation zone removals, despite the formulation of Equation (47) to account for only the evaporation zone removal. The applicability of Equation (48) to the system removals also suggest further study of the SO_2 removal phenomena leading to SO_2 removal taking place after slurry droplet have evaporated to surface dryness. Equation (48) also appears to include wall effects which are present in the present data.

SO_2 Removal By Wall Deposits---

An estimate of SO_2 removal by Station 1 wall deposits was made by measuring the SO_2 concentration at the end of the Station 1 duct (at the duct position having 1 or 2s residence time at 50 or 25 kcfm) soon after the lime and water supply to the atomizer were turned off. The initial SO_2 removal activity of wet wall deposits is not expected to be seriously affected by the flue gas moisture without atomizer humidification not corresponding to that during which SO_2 removal was measured earlier. Table 7 shows a summary of the SO_2 concentrations at the beginning and end of the Station 1 duct (evaporation zone) after the atomizer feed is turned off. In some tests, the SO_2 outlet concentration is higher than at the inlet. This is probably partly due to time variation in the inlet SO_2 concentration, and partly to slight instrumentation inaccuracy. Table 7

shows that the SO₂ removal due to duct wall deposits measured in this way is in the range of 0 to 4.4 %, with an average of about 1.2%. The small extent of the wall deposit removal is probably due to the deposits being localized and hence not providing any appreciable surface area for mass transfer.

TABLE 7. SO₂ REMOVAL BY WALL DEPOSITS AFTER ATOMIZER FEED SHUT-OFF

TEST NO.	INLET GAS FLOW RATE, kcfm	SO ₂ CONCENTRATION, ppmv(wet)		WALL DEPOSIT SO ₂ REMOVAL EFFICIENCY, %
		INLET	STN 1 OUTLET	
5	24.9	2939	3066	0.0
6	25.0	2911	2957	0.0
7	25.0	2937	2867	2.4
8	50.4	3056	3039	0.0
10	23.5	3043	2987	1.8
12	22.3	3027	3014	0.0
16	22.5	3286	3140	4.4
18	41.4	3152	3225	0.0
26	41.9	3183	3113	2.2

Station 2

Velocity Distributions---

Simultaneous measurements of the gas velocity were obtained at 9 points of the duct cross section immediately upstream and immediately downstream of the rotary atomizer and approximately 30 ft downstream of the atomizer. The sensing technique was a modified hot-wire approach developed by the Kurz Instrument Company. Data were obtained at a nominal 50,000 cfm of flue gas at 330F for all nine anemometer locations in the 50-in wide by 40-in high duct without slurry addition, but with the atomizer in place and spinning. The discrete velocity measurements were analyzed by Golden Software's "SURFER" program. The profiles thus generated are shown in Figure 52. Immediately upstream (6 ft or 0.1 average residence time) of the atomizer the average gas velocity was 3656 ft/min +/- a standard deviation of 369 ft/min (or 10%), indicating good closure with respect to the 50,000 cfm volumetric flow measured by the venturi. The average velocity to the right side exceeded the left by about 8%, and the average velocity at the center by about 11%. Immediately downstream of the atomizer the average velocity was 3542 ft/min +/- 485 ft/min standard deviation. The right side exceeded the left side by 15% in this case. Furthermore, the velocity at the bottom of the duct was increased relative to the top. Thus, the presence of the atomizer created only minor variations in the flow profile.

At the 0.5 second (30 ft) position, the average velocity was 3377 ft/min + 350 ft/min standard deviation. The right to left and right to center bias were more pronounced at 13% and 15% levels. The lower standard deviation reflected less top to bottom variation.

Even though measurable gas velocity variations were observed, the standard deviations of less than + 15% are typical for well designed duct work. Attempts to use the multi-point velocity probes during atomizer operation proved unsuccessful due to wetting of the sensors and the corresponding tendency for the sensors to erroneously report latent heat as an increased velocity.

Gas Temperature Distribution---

Although velocity measurements during slurry injection could not be made, temperature results were obtainable and are presented in Figure 53. The temperature profiles were measured across the same 3X3 grids spanned by the anemometer probes. As with the velocity measurements, temperature data were obtained at a nominal 50,000 cfm of flue gas at 330 F for all three locations in the 50-in wide by 40-in high duct with slurry addition. The discrete temperature measurements were analyzed by Golden Software's "SURFER" program. The smoothing of the temperature profiles shown in Figure 53 were made through interpolations between data points. In the atomizer near field (0.1 sec/6 ft) significant temperature variation was observed, with the left side about 10 degrees higher than the right side, and with a pronounced hot spot in the center of the duct. Further downstream, at the 0.5 second point (30 ft downstream of the atomizer), the duct temperature profile had smoothed considerably showing that good mixing had occurred. At this point, the average gas temperature of 198 F

50 Kacfm, 330 °F

Figure 52. Velocity profiles across Station 2 duct cross-sections at 0, 30, and 60 ft downstream of the atomizer at the design inlet gas flow rate of 50 kacfm, with no gas flow conditioning device.

Figure 53(a). Temperature profile across Station 2 duct cross-section at 6 ft downstream of the atomizer at the design inlet gas flow rate of 50 kacfm, inlet gas temperature of 350 F, and 13.3 gpm lime slurry flow rate through the atomizer spinning at 14 krpm with no gas flow device.

Figure 53(b). Same as Figure 53(a), but across Station 2 duct cross-section 30 ft downstream of the atomizer.

indicated nearly complete evaporation since the slurry injection rate of 13.3 gpm yields a calculated equilibrium gas temperature of 190 F.

Wall Temperature---

As in Station 1, the grid of duct wall thermocouples (positioned as shown in Figure 9) proved to be effective in obtaining important process information, and to evaluate the efficacy of flow devices used to modify and optimize gas flow and droplet dispersion. Table 8 (below) summarizes all the tests performed with measurements of the boundary layer temperatures.

The results of the wall temperature investigations listed in Table 8 may be summarized as follows:

1. See Figure 54. The wetting potential with water at a 50 kcfm gas flow rate with a 14 krpm atomizer rpm is observed to fluctuate with respect to water flow rate. With no flow device and the atomizer spinning at 14 krpm (counter-clockwise when viewed from the top of the duct), non-wetting characteristics are observed on all sides of the duct except right wall about 4 ft from the atomizer when the water flow rate is 1.9 gpm. Wetting, as indicated by the wall temperature being close to the wet bulb temperature is observed for this right side location. As the water flow rate is doubled to 3.8 gpm, the right wall dramatically recovers from the wetting condition observed for the lower water flow rate. All other sides maintain their mostly non-wetting temperature profiles. A region of the ceiling about 8 ft downstream of the atomizer shows a temperature below 160 F indicating possibly some light wetting. As the water flow rate is increased further to about 4.6 gpm, the ceiling appears to be wetted up to about 4 ft downstream of the atomizer (in the immediate vicinity of the atomizer). All other duct regions appear dry. The left wall shows signs of wetting, in addition to the ceiling region close to the atomizer, when the flow rate is increased slightly to 4.9 gpm.
2. See Figure 55. At the 50 kcfm gas flow rate with no gas flow devices and the atomizer angular speed remaining at 14 krpm (counter-clockwise as viewed from the top of the duct), the wetting characteristics observed for lime, having a solids mass fraction of about 20%, are different from those observed for water. The fluctuating wetting potential observed for water with increasing liquid flow rate is absent for lime. In the case of lime the wetting potential appears to degrade gradually with increasing lime flow rate. Non-wetting ducts are observed for lime slurry flow rates up to 3.6 gpm (wall temperatures above 200 F). For flow rates up to 6.6 gpm, only minor wall wetting is observed on all sides of the duct (wall temperatures above 160 F). The right wall region about 4 ft from the atomizer wheel shows evidence of severe wetting at lime slurry

TABLE 8. SUMMARY OF EXPERIMENTS WITH BOUNDARY LAYER TEMPERATURE MEASUREMENTS

DATE	TIME	GAS FLOW RATE, kcfm	LIME FLOW RATE, gpm	WATER FLOW RATE, gpm	EFFECT INVESTIGATED	FIGURE NO.
9/16/87	14:01	57	0.0	5.65	24" wing @ 15 ⁰ , 31" at nose	57(a)
9/21/87	12:27	57	0.0	5.63	24" wing @ 10 ⁰ , 31" at nose	57(b)
9/21/87	16:32	56	0.0	5.63	24" wing @ 7 ⁰ , 31" at nose	57(c)
9/24/87	13:43	53	0.0	3.48	13" wing @ 15 ⁰ , 31" at nose	59(b)
9/24/87	14:03	56	0.0	5.64	13" wing @ 15 ⁰ , 31" at nose	58(a)
9/24/87	16:02	56	0.0	5.64	13" wing @ 10 ⁰ , 31" at nose	58(b)
9/29/87	16:59	55	0.0	5.62	13" wing @ 5 ⁰ , 31" at nose	58(c)
9/29/87	12:21	29	0.0	5.34	13" wing @ 5 ⁰ , 31" at nose	62
10/5/87	17:12	24	5.36	0.0	13" wing @ 5 ⁰ , 31" at nose	63(b)
10/5/87	23:57	24	3.53	0.0	13" wing @ 15 ⁰ , 31" at nose	63(a)
10/7/87	13:04	27	2.18	0.0	13" wing @ 20 ⁰ , 31" at nose	61
10/7/87	13:35	50	0.0	3.84	13" wing @ 20 ⁰ , 31" at nose	58(d)
10/7/87	15:56	50	3.34	0.0	13" wing @ 20 ⁰ , 31" at nose	59
10/7/87	16:25	51	5.57	0.0	13" wing @ 20 ⁰ , 28" at nose	60(a)
10/7/87	16:49	50	5.88	0.0	13" wing @ 19 ⁰ , 29" at nose	60(b)
10/8/87		50	0.0	1.9 to 4.9	No flow device	54
10/8/87		50	2.0 to 11.2	0.0	No flow device	55
10/8/87	13:50	55	7.62	0.0	13" wing @ 19 ⁰ , 29" at nose	60(c)
10/8/87	14:46	54	8.46	0.0	13" wing @ 19 ⁰ , 29" at nose	60(d)
10/8/87	16:03	52	11.78	0.0	13" wing @ 19 ⁰ , 29" at nose	60(e)
10/8/87	17:00	52	14.16	0.0	13" wing @ 19 ⁰ , 29" at nose	60(f)

TABLE 8 (Cont'd...). SUMMARY OF EXPERIMENTS WITH BOUNDARY LAYER
TEMPERATURE MEASUREMENT

DATE	TIME	GAS FLOW RATE, kcfm	LIME FLOW RATE, gpm	WATER FLOW RATE, gpm	EFFECT INVESTIGATED	FIGURE NO.
10/13/87		47	0.0	3.7	13" wing @ 19 ⁰ , 29" at nose 10 krpm	64(a)
10/13/87		47	0.0	3.5	13" wing @ 19 ⁰ , 29" at nose 12.3 krpm	64(b)
10/13/87		40	0.0	3.5	13" wing @ 19 ⁰ , 29" at nose 14.1 krpm	64(c)
10/20/87	13:52	52	6.3	0.0		81
10/20/87	14:04	52	6.3	0.0		82
10/29/87	11:13	51	0.0	3.42	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5", Right flap @ 5"	65(a)
10/29/87	11:22	51	0.0	3.48	13" wing @ 19 ⁰ , 28" at nose Left flap @ 7", Right flap @ 5"	65(b)
10/29/87	11:33	52	0.0	3.52	13" wing @ 19 ⁰ , 28" at nose Left flap @ 7", Right flap @ 7"	65(c)
10/29/87	11:41	52	0.0	3.54	13" wing @ 19 ⁰ , 28" at nose Left flap @ 6", Right flap @ 7"	65(e)
10/29/87	11:52	52	0.0	3.55	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5.5", Right flap @ 7"	65(d)
10/29/87	13:09	53	0.0	5.61	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5.5", Right flap @ 7"	65(f)
10/29/87	14:47	56	5.65	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5.5", Right flap @ 7.5"	66(c)
10/29/87	15:27	57	5.37	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5.5", Right flap @ 7.5"	66(d)
10/30/87	14:08	28	3.27	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 6", Right flap @ 8"	67(b)
10/30/87	17:17	28	2.99	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 11", Right flap @ 11"	67(a)
11/2/87	11:49	29	3.15	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5.5", Right flap @ 7.5"	67(c)

TABLE 8 (Cont'd...). SUMMARY OF EXPERIMENTS WITH BOUNDARY LAYER
TEMPERATURE MEASUREMENT

DATE	TIME	GAS FLOW RATE, kcfm	LIME FLOW RATE, gpm	WATER FLOW RATE, gpm	EFFECT INVESTIGATED	FIGURE NO.
11/2/87	14:56	55	5.70	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 11", Right flap @ 11"	66(a)
11/2/87	17:34	27	2.84	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5", Right flap @ 8.5"	67(d)
11/3/87	15:50	56	5.40	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5", Right flap @ 8.75"	66(f)
11/4/87	15:32	56	5.65	0.0	13" wing @ 19 ⁰ , 28" at nose Left flap @ 5", Right flap @ 8.75"	66(e)
11/23/87	14:54	53	1.50	13.92	13" wing @ 23 ⁰ , 27" at nose Left flap @ 5", Right flap @ 8.75"	68
12/7/87		25	1.0 to 6.0	0.0	No flow device	56
12/7/87		25	3.00	0.0	No flow device, no additive to lime	70
12/7/87		25	3.00	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone added to lime 8 atomizer holes	70
12/7/87		25	4.00	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone	71
12/7/87		25	5.00	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone	72
12/7/87		25	6.00	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone	73
12/7/87		25	3.00	0.0	No flow device, 1000 ppm surfactant + 1000 ppm GE silicone	70

TABLE 8 (Cont'd...). SUMMARY OF EXPERIMENTS WITH BOUNDARY LAYER
TEMPERATURE MEASUREMENT

DATE	TIME	GAS FLOW RATE, kcfm	LIME FLOW RATE, gpm	WATER FLOW RATE, gpm	EFFECT INVESTIGATED	FIGURE NO.
12/7/87		25	4.00	0.0	No flow device, 1000 ppm surfactant + 1000 ppm GE silicone	71
12/7/87		25	5.00	0.0	No flow device, 1000 ppm surfactant + 1000 ppm GE silicone	72
12/7/87		25	6.00	0.0	No flow device, 1000 ppm surfactant + 1000 ppm GE silicone	73
12/7/87		25	236F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 8 atomizer holes	74
12/7/87		25	236F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 4 atomizer holes	74
12/7/87		25	236F Out -let	0.0	Optimized flaps 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	74
12/7/87		25	236F Out -let	0.0	wing @ 20° 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	74
12/7/87		25	233F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 8 atomizer holes	75
12/7/87		25	233F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 4 atomizer holes	75
12/7/87		25	233F Out -let	0.0	Optimized flaps 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	75

TABLE 8 (Cont'd...). SUMMARY OF EXPERIMENTS WITH BOUNDARY LAYER TEMPERATURE MEASUREMENT

DATE	TIME	GAS FLOW RATE, kcfm	LIME FLOW RATE, gpm	WATER FLOW RATE, gpm	EFFECT INVESTIGATED	FIGURE NO.
12/7/87		25	223F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 8 atomizer holes	76
12/7/87		25	223F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 4 atomizer holes	76
12/7/87		25	223F Out -let	0.0	Optimized flaps 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	76
12/7/87		25	212F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 8 atomizer holes	77
12/7/87		25	212F Out -let	0.0	No flow device, 500 ppm surfactant + 500 ppm GE silicone 4 atomizer holes	77
12/7/87		25	212F Out -let	0.0	Optimized flaps 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	77
12/7/87		50	13	0.0	No flow device 1000 ppm surfactant + 1000 ppm GE silicone 8 atomizer holes	78
12/7/87		50	13	0.0	No flow device 500 ppm surfactant + 500 ppm GE silicone 4 atomizer holes	78
12/7/87		50	13	0.0	Wing @ 20° 500 ppm surfactant + 500 ppm GE silicone 2 atomizer holes	78

(a) Top

(b) Bottom

(c) Right

(d) Left

Figure 54. Effect of water flow rate on Station 2 boundary layer temperatures on: (a) top, (b) bottom, (c) right, and (d) left sides for an inlet gas flow rate of 50 kacfm and atomizer angular speed of 14 krpm with no gas flow distribution device.

(a) Top

(b) Bottom

(c) Right

(d) Left

Figure 55. Effect of lime flow rate on Station 2 boundary layer temperatures on: (a) top, (b) bottom, (c) right, and (d) left sides for an inlet gas flow rate of 50 kacfm and atomizer angular speed of 14 krpm with no gas flow distribution device.

flow rate higher than 9 gpm. The onset of severe wetting on the left duct occurs at a higher flow rate of 11.2 gpm. On this side, the area of localized wetting occurs just opposite the atomizer wheel. The ceiling and floor walls show only slight wetting. The lowest ceiling wall temperature at the highest lime slurry flow rate tested (11.2 gpm) dipped only slightly below 160 F. The bottom wall appeared to have stayed nearly completely dry for all lime slurry flow rates up to 11.2 gpm.

3. See Figure 56. The wetting patterns with respect to flow rate of lime (having a solids mass fraction of 20%) are essentially the same when the gas flow rate is decreased to 25 kcfm, when the atomizer rotation is counter-clockwise as viewed from the top of the duct and the lime slurry solids mass fraction is about 20%. At a lime flow rate of 1 gpm completely non-wetting behavior results. As the lime flow rate is increased to 2 gpm, the region of the right wall about 4 ft from the atomizer appears to show signs of minor wetting. The other walls remain non-wetting. Further increase of the lime flow rate to 3 gpm is accompanied by a degradation of the left wall close to the atomizer to minor wetting conditions. The right wall wetting appears confined to the same location observed for the higher flow. The ceiling and floor appear devoid of any wetting. The wetting extent of the right wall within about 4 ft of the atomizer shows a stepwise deterioration as the lime flow rate is increased to 4 gpm. The wetting region on the right wall spreads to include the region from 0 to 4 ft of duct. The area of the right side duct directly opposite the atomizer wheel show temperatures close to the wet-bulb temperature indicative of severe wetting at a lime slurry flow rate of 5 gpm. The area of the right side duct directly opposite the atomizer wheel show temperatures close to the wet-bulb temperature indicative of severe wetting at a lime slurry flow rate of 5 gpm. This wetting profile remains about the same for a 6 gpm lime slurry flow rate also. For lime flow rates in the range 3 to 6 gpm, the left wall wetting profile remains the same. The region of left duct directly opposite the atomizer wheel show a wall temperature of about 160 F indicative of some slight droplet impingement on this region of the left duct for lime flow rates between 3 and 6 gpm. The ceiling and floor appear to be nearly completely devoid of wetting except possibly at the highest lime slurry flow rate (6 gpm).
4. See Figure 57. At 50 kcfm gas flow and 5.65 gpm water flowing to the atomizer rotating at 14 krpm, the 24 in. wing (see also Figure 12) improves the top to bottom temperature distribution, but not the left to right distribution. In the presence of the wing, the right side showed severe wetting all the way to about 24 ft from the atomizer. The wing at the 7° angle gave the optimum floor and ceiling profiles. The 20° angle improved only the floor profile. The ceiling profile was progressively improved by decreasing the wing angle to the 7° degree optimum value.

Figure 56. Effect of lime flow rate on Station 2 boundary layer temperatures on: (a) top, (b) bottom, (c) right, and (d) left sides for an inlet gas flow rate of 25 kacfm and atomizer angular speed of 14 krpm with no gas flow distribution device.

Figure 57(a). Effect of a 24-in. airfoil placed at a 15° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 50 kacfm and a water flow rate of 5.65 gpm through the atomizer spinning at 14 krpm.

Figure 57(b). Same as in Figure 57(a) except for a 10° orientation.

5. See Figure 58. At 50 kcfm gas flow and 5.65 gpm water flowing in the atomizer spinning at 14 krpm, the 13" wing gave nearly the same ceiling and floor profiles as the 24" wing at 10° degrees. However, as the angle of the 13 in wing is decreased below the 15° degree value, further improvement of the floor profile was accompanied only by a deterioration of the ceiling profile. The 24 in wing at 7° angle yielded slightly warmer floor and ceiling profiles than the 13 in wing at the 15° angle.

At 50 kcfm gas flow, with the 13 in wing at 15° angle, and 3.5 gpm water flowing in the atomizer spinning at 14 krpm, all wall temperatures are above 160F, well above the wet-bulb temperature of 127F, and probably indicative of non-wetting or nearly non-wetting operation of the atomizer at this flow rate. The coldest spot (160F) is on the top, and 8 ft downstream from the atomizer.

The wall temperatures corresponding to a water flow rate of 4.9 gpm shown in Figure 54 are slightly warmer, in general, than those shown in Figure 58 which correspond to a higher water flow rate of 5.6 gpm in the presence of the airfoil upstream of the atomizer. This fact indicates that the airfoil may be effective in increasing only slightly the water flow rate at which wetting onset occurs.

6. See Figure 59. At 50 kcfm gas flow, with the 13 in wing at 20°, and 3.3 gpm lime slurry (20% solids mass fraction) flowing in the atomizer spinning at 14 krpm, all wall temperatures are above 200 F, compared with the 160F value obtained as the lowest temperature with water at nearly the same flow. This result is consistent with previous results indicating warmer wall temperatures with lime slurry than with water.
7. See Figure 60. When the gas flow rate is 50 kcfm, with the 13 in. wing at 20° angle and a 28 in. nose position (dropped 3 in. from its 31 in. position in all the previous descriptions above), the floor region directly below the atomizer appears to show significant wetting. All other walls appear devoid of serious wetting. All four wall temperatures converge to nearly the same value as the outlet gas temperature after about a 0.4 gas residence time, (or after about 24 ft downstream of the atomizer). The wall temperature profiles with the airfoil in this setting (Figure 60(a)) appear to show greater wetting extent than those shown in Figure 55 without the airfoil. When the airfoil nose position is increased to 29 in. and the airfoil approach angle decreased to 19°, all other parameters remaining the same, no wall temperature is below 165 F despite a slightly higher lime slurry flow rate of 5.88 gpm. This result is indicative of non-wetting or nearly non-wetting temperature profiles induced by this wing setting at this flow rate of lime slurry. When the lime slurry flow rate is increased to 7.62 gpm while maintaining the wing at the same position, the right and left wall regions opposite to the atomizer show evidence of severe wetting. The ceiling region about 4 ft from the atomizer

Figure 57(c). Same as in Figure 57(a) except for a 70° orientation.

Figure 58(a). Effect of a 13-in. airfoil placed at a 15° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 50 kacfm and a water flow rate of 5.65 gpm through the atomizer spinning at 14 krpm.

Figure 58(b). Same as in Figure 58(a) except for a 10° orientation.

Figure 58(c). Same as in Figure 58(b) except for a 5° orientation.

Figure 58(d). Effect of a 13-in. airfoil placed at a 20° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 50 kacfm and a water flow rate of 3.8 gpm through the atomizer spinning at 14 krpm.

Figure 58(e). Same as in Figure 58(d), except for a 15° airfoil angle.

Figure 59. Effect of a 13-in. airfoil placed at a 20° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 50 kacfm and a lime slurry flow rate of 3.3 gpm through the atomizer spinning at 14 krpm.

Figure 60(a). Effect of a 13-in. airfoil placed at a 20° angle and 28 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 50 kacfm and a lime slurry flow rate of 5.6 gpm through the atomizer spinning at 14 krpm.

Figure 60(b). Same as Figure 60(a) except for a 5.9 gpm lime slurry flow rate with a 19° airfoil angle and 29 in. nose position.

Figure 60(c). Same as Figure 60(b) except for a 7.6 gpm lime slurry flow rate

Figure 60(d). Same as Figure 60(b) except for a 8.5 gpm lime slurry flow rate

Figure 60(e). Same as Figure 60(b) except for a 11.8 gpm lime slurry flow rate

appears to get a slight shower of droplets. Slight wetting also appears to be evident on the right wall all the way up to about 20 ft from the atomizer (wall temperature above 160 F). Increasing the lime slurry flow rate once more to 8.5 gpm appears to reduce the severity of wetting on the left wall opposite the atomizer, but leaves the severe wetting condition on the right wall opposite the atomizer unchanged. The ceiling and right wall at 4 ft from the atomizer still shows evidence of slight wetting (wall temperature is about 160 F). At this higher slurry flow rate, the minor wetting along the right wall up to 20 ft from the atomizer appears to be alleviated to some extent as evidenced by the higher wall temperatures. Localized wetting, while still occurring at the right wall opposite the atomizer at an even higher slurry flow rate of 11.8 gpm, also occurs at an additional location. This additional location is on the ceiling about 16 ft from the atomizer. Beyond 12 ft from the atomizer, all four sides of the duct display wall temperature profiles close to each other, indicating uniform humidification of the gas in this case. Finally, the lime slurry flow rate was increased to 14 gpm sufficient for obtaining an approximately 50° approach to saturation at the outlet of the Station 2 duct. At this slurry flow rate, the localized wetting near the atomizer on all sides but the floor persist. However, the cold spot on the ceiling 12 ft from the atomizer observed for the 11.8 gpm slurry flow rate is absent. Lower wall temperatures are now observed for the left wall than for the right wall. The wall temperature profiles are not as close together as observed for the 11.8 gpm flow rate. The closeness among the profiles improves only beyond 24 ft from the atomizer, again indicating uniform droplet/gas mixing and humidification after this distance.

8. See Figure 61. At 25 kcfm gas flow, with the 13 in wing at 20°, and 2.2 gpm water flowing in the atomizer spinning at 14 krpm, the right wall roughly 4 ft downstream from the atomizer indicates a wall temperature close to the wet-bulb temperature (about 125F), and thus shows evidence of wetting. The left wall temperature 4 ft from the atomizer wheel is slightly higher than the wet-bulb temperature, probably indicating some slight wetting at this location also. In addition, there is evidence of floor wetting about 16 ft downstream of the atomizer.
9. See Figure 62. At 29 kcfm gas flow rate and increased water flow at 5.3 gpm, the 13 in wing at 5° angle, all other parameters remaining the same, all sides of the duct except, the ceiling, up to about 20 ft downstream of the atomizer show evidence of wetting.
10. See Figure 63. At 24 kcfm gas flow rate, with the 13 in wing at 15° angle, and lime slurry flowing at 3.5 gpm in the atomizer spinning at 14 krpm, significant wetting is observed on the right and left walls about 4 ft downstream of the atomizer. When the slurry flow rate is increased slightly to 3.7 gpm, the wing remaining configured as before, the wetting pattern is not

Figure 60(f). Same as Figure 60(b) except for a 14.2 gpm lime slurry flow rate

Figure 61. Effect of a 13-in. airfoil placed at a 20° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 25 kacfm and a water flow rate of 2.2 gpm through the atomizer spinning at 14 krpm.

Figure 62. Effect of a 13-in. airfoil placed at a 5° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 28.5 kacfm and a water flow rate of 5.3 gpm through the atomizer spinning at 14 krpm.

Figure 63(a). Effect of a 13-in. airfoil placed at a 15° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 23.8 kacfm and a lime slurry flow rate of 3.5 gpm through the atomizer spinning at 14 krpm.

Figure 63(b). Effect of a 13-in. airfoil placed at a 15° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 23.3 kacfm and a lime slurry flow rate of 3.7 gpm through the atomizer spinning at 14 krpm.

Figure 63(c). Effect of a 13-in. airfoil placed at a 15° angle and 31 in. nose height upstream of the atomizer on Station 2 boundary layer temperatures for an inlet gas flow rate of 23.8 kacfm and a lime slurry flow rate of 5.4 gpm through the atomizer spinning at 14 krpm.

altered significantly, except for the spreading of the wetting zone to include the right and left wall regions directly opposite to the atomizer. As the lime slurry flow rate is increased to 5.4 gpm, all other parameters remaining the same, the wetting extent spreads even further across the first 12 ft from the atomizer on all sides of the duct except possibly the top side. As in the case of the 50 kcfm gas flow rate, the wetting profile observed with lime is less severe than that for water at the same flow rate. In the latter case, as discussed in item 6 above, the wetting region extends up to about 20 ft downstream of the atomizer on all sides of the duct including the ceiling.

11. See Figure 64. The effect of changing the atomizer angular speed was investigated in the presence of the 13 in wing placed at the 19° angle with its nose at the 29 in position. At the 50 kcfm gas flow rate and an approximate lime slurry flow rate of 3.6 gpm, a 13.5 krpm angular speed provided slightly higher minimum wall temperature (142 F occurring on the right wall 4 ft from the atomizer), than a 14 krpm angular speed (139 F occurring at the same location). Beyond about 20 ft from the atomizer, the wall temperatures on all four duct walls are closer together for the higher angular speed than the lower speed, indicating possibly finer atomization and consequently faster evaporation in the case of the higher rpm.
12. See Figure 65. In addition to the central airfoil oriented for an upward drag force, two additional airfoils or flaps placed close to the right and left walls and oriented so the resulted drag forces are horizontal (see Figure 13), were tested as a means to alleviate the localized wetting observed on the right and left walls within 4 ft of the atomizer wheel. Figure 64 shows the effect varying the flap positions on the wall temperature profiles with water flowing in the atomizer which is spinning at 14 krpm. Increasing the left flap position to 7 in while maintaining the right flap at 5 in results in slightly higher right wall temperatures. Increasing the right flap position to 7 in appears to be even more effective in increasing the right wall temperature. However, the ceiling temperatures near the atomizer remain low and unchanged. A right flap position of 7 in and left flap position of 5.5 in appears to be optimal with respect to wall temperature profiles. The low ceiling temperatures within 4 ft of the atomizer representative of wetting onset appears unaffected by flap adjustments. Increasing the water flow rate to 5.6 gpm while maintaining the airfoil and flaps at their previous positions results in significant wetting on all sides except the floor all the way down to 20 ft from the atomizer.
13. See Figure 66. The flaps were also optimized separately at a 50 kcfm gas flow rate for lime slurry flowing at about 5.5 gpm in the atomizer rotating at 14 krpm. A relatively open flap positions of 11 in for both flaps results in lower right wall temperatures close to the atomizer. Decreasing the right flap

Figure 64(a). Effect of a 10 krpm atomizer angular speed on Station 2 boundary layer temperatures (with the 13 in. airfoil placed at a 19° angle and 28 in. nose height) for an inlet gas flow rate of 50 kacfm and a water flow rate of 3.7 gpm through the atomizer.

Figure 64(b). Same as in Figure 64(a) except for a 12.3 krpm atomizer angular speed.

Figure 64(b). Same as in Figure 64(a) except for a 14 krpm atomizer angular speed.

Figure 65(a). Effect of fixed airfoil (13 in. wing placed at optimal 190 angle and 28 in. nose height) and variable left and right airflap nose positions for a 50 kacfm inlet gas flow rate, 3.4 gpm water flow rate and 14 krpm atomizer angular speed. Above figure for a 5 in. left and right airflap tail positions.

Figure 65(b). Same as in Figure 65(a) except for a 7 in. left airflap tail position.

Figure 65(c). Same as in Figure 65(a) except for a 7 in. left and right airflap tail positions.

Figure 65(d). Same as in Figure 65(a) except for a 6 in. left airflap and 7 in. right airflap tail positions.

Figure 65(e). Same as in Figure 65(a) except for a 5.5 in. left airflap and 7 in. right airflap tail positions.

Figure 65(f). Same as in Figure 65(e) except for a 5.61 gpm water flow rate.

Figure 66(a). Effect of fixed airfoil (13 in. wing placed at optimal 19o angle and 28 in. nose height) and variable left and right airflap nose positions for a 50 kacfm inlet gas flow rate, 5.7 gpm lime slurry flow rate and 14 krpm atomizer angular speed. Above figure for a 11 in. left and right airflap tail positions.

Figure 66(b). Same as in Figure 66(a) except for a 5.5 in. left airflap and 7 in. right airflap tail positions.

Figure 66(c). Same as in Figure 66(a) except for a 5.5 in. left airflap and 7.5 in. right airflap tail positions.

Figure 66(d). Same as in Figure 66(c) except for a 5.4 gpm lime slurry flow rate.

Figure 66(e). Same as in Figure 66(a) except for a 5 in. left airflap and 8.75 in. right airflap tail positions.

position to 8.75 in and the left flap position to 5 in has a dramatic effect of increasing all wall temperatures above 190 F except for an area 4 ft from the atomizer on the left wall which shows about a 170 F temperature. Fine tuning the right flap to a 7.5 in. position and the left flap at 5.5 in. eliminates the 170 F spot on the left wall, but at the expense of lowering the right wall temperature profile within 12 ft from the atomizer by 60 F. Overall, the wall temperatures are still above 175 F, and appear to represent nearly non-wetting operation of the atomizer. Increasing the lime slurry flow rate to 5.65 gpm brings the left wall temperatures near the atomizer in line with those observed on the opposite wall. The essentially non-wetting characteristic of atomizer operation appear to be still preserved at this flow rate. The right flap position of 8.75 in. and left flap position of 5 in. appears to yield the best non-wetting characteristics under these conditions. When the lime slurry flow rate is increased to 14.4 gpm corresponding to an approach to saturation of about 50 F, the flaps do not appear to control the wetting as well as they did at the lower slurry flow rate. Wetting is observed on the right, left and floor walls up to 4 ft from the atomizer. Wetting of the right and floor walls persist up to 8 ft from the atomizer. Floor wetting is the worst extending up to 12 ft from the atomizer. Beyond 12 ft, all wall temperature profiles are closely spaced indicating uniform droplet dispersion and humidification beyond 12 ft from the atomizer.

14. See Figures 67 and 68. The flaps were also optimized with 3 gpm of lime slurry flowing in the atomizer rotating at 14 krpm, with a 25 kcfm of gas flow. The starting flap positions of 11 in on both sides yielded wall temperature profiles somewhat similar to those observed previously for a higher gas flow rate of 50 kcfm. For both flow rates the right wall yielded the lowest temperature profiles. Reducing the flap positions lead to gradual improvement of the wall wetting characteristics. A right flap position of 8.5 in and a left flap position of 5 in appeared to be optimal for producing the best non-wetting characteristic. These flap settings were optimal for the higher gas flow rate also. Increasing the lime slurry flow rate to 13.9 gpm together with a water flow rate of 1.5 gpm to obtain a approach to saturation of about 50 F resulted in the now familiar wall wetting in the neighborhood of the atomizer. Beyond about 8 ft downstream of the atomizer, the wall temperatures indicate nearly non-wetting characteristics. Figure 68 in effect summarizes the end effect of the above experimentation with gas flow conditioning devices. The gas flow conditioning devices, while having the effect of nearly non-wetting behavior for lime slurry flow rates of up to 6 gpm, were not effective in eliminating the near-atomizer wetting at lime slurry flow rates high enough for obtaining the target SO₂ removal efficiency of 50%.

Figure 66(f). Same as in Figure 66(e) except for a 5.4 gpm lime slurry flow rate.

Figure 67(a). Effect of fixed airfoil (13 in. wing placed at optimal 19° angle and 28 in. nose height) and variable left and right airflap nose positions for a 28 kacf_m inlet gas flow rate, 3 gpm lime slurry flow rate and 14 krpm atomizer angular speed. Above figure for a 11 in. left and right airflap tail positions.

Figure 67(b). Same as in Figure 67(a) except for a 6 in. left airflap and 8 in. right airflap tail positions.

Figure 67(c). Same as in Figure 67(a) except for a 5.5 in. left airflap and 7.5 in. right airflap tail positions.

Figure 67(d). Same as in Figure 67(a) except for a 5 in. left airflap and 8.5 in. right airflap tail positions.

Figure 68. Same as in Figure 67(a) except for a 5 in. left airflap and 8.75 in. right airflap tail positions, and 13.9 gpm lime slurry and 1.5 gpm dilution water flow rates required for a 50 F approach to saturation.

15. The effect of using surfactant added to the lime slurry for alleviating the wall wetting previously observed for high lime slurry flow rates, was investigated in a series of tests using only the wall temperatures as indicators of potential wall wetting. Figure 69 shows the lowering in surface tension of lime to be expected from adding Turgitol (surfactant) with 500 ppm (by mass) of anti-foam agent (GE silicone) to the lime. The surface tension measurements shown in the figure was obtained from measurements of the number of droplets formed as treated slurry from a pipette is allowed to flow gently out of the pipette. The surface tension of the treated lime was obtained by this technique by applying a suitable scaling of the droplet volume data in comparison with the droplet volume of water.
16. See Figures 70 to 73. The effect of surfactant was initially tested at a gas flow rate of 25 kcfm, atomizer angular speed of 14 krpm, with no gas flow corrective devices. The effect of 500 ppm of turgitol and 500 ppm of GE-silicone on the wall temperature profile was studied as a function of the treated lime slurry flow rate. At a lime slurry flow rate of 3 gpm, surfactant addition yielded significantly higher boundary layer temperatures on all sides of the duct except the right wall. At this wall, the wall temperature 4 ft from the atomizer is significantly depressed from its value for the untreated lime. The temperature 8 ft from the atomizer is also slightly lower. In contrast, the temperature on the right side directly opposite the atomizer is significantly higher than the value for the untreated lime. Beyond 12 ft from the atomizer, the surfactant improves the right wall temperature also. The mostly higher wall temperatures for the surfactant laden slurry indicates better droplet confinement within the duct in the presence of the additive at this flow rate, except the right wall close to the atomizer. The above difference in the near-atomizer right wall temperature between the untreated and treated lime slurries becomes less pronounced as the slurry flow rate is increased to 4 gpm. At this slurry flow rate, the right wall temperature closest to the atomizer is below the value for the untreated lime. The top wall and the left wall temperature profiles are higher for the treated lime. The floor and right wall profiles are also higher except at one point. In the case of the floor, this point is about 12 ft from the atomizer. In the case of the right wall, as discussed above, this point is directly opposite the atomizer. Generally, at a higher flow rate of the surfactant-treated lime slurry (5 gpm), the ceiling and left wall temperatures appear warmer and are comparable to those obtained lower flow rates of untreated lime. However, there is a slight lowering of the left wall temperature at one location directly opposite the atomizer. The floor temperatures with the treated lime are higher up to about 8 ft from the atomizer, but then cross over to be below the temperatures for the untreated lime. The right wall temperatures are generally below those corresponding to the untreated lime. When the lime slurry flow rate is increased to 6 gpm, it is the ceiling and floor temperatures which appear warmer than those corresponding to the

Figure 69. Effect of surfactant concentration on lime slurry surface tension.

Figure 70. Effect of surfactant concentration on Station 2 boundary layer temperatures for an inlet gas flow rate of 25 kacfm and a lime slurry flow rate of 3 gpm, and atomizer angular speed of 14 krpm, with no gas flow distribution devices.

Figure 71. Same as in Figure 70, except for a 4 gpm lime slurry flow rate.

Figure 72. Same as in Figure 70, except for a 5 gpm lime slurry flow rate.

Figure 73. Same as in Figure 70, except for a 6 gpm lime slurry flow rate.

lime without surfactant, instead of the ceiling and left walls observed to have the higher temperatures at the lower slurry flow rates. The right wall profile shows lower temperatures all along the wall with surfactant addition. The left wall appears slightly warmer. The left wall temperatures are at least as good as the no additive case beyond 16 ft from the atomizer. The left wall temperatures are below their values corresponding to untreated lime up to 12 ft from the atomizer. It is important to demonstrate non-wetting operation with lime slurry flow rates higher than 6 gpm in order to achieve the required lime stoichiometric ratio and approach to saturation for appreciable SO_2 removal.

The effect of increasing the surfactant and anti-foam concentrations was investigated at the 25 kcfm gas flow rate, with no gas flow device and the atomizer spinning at 14 krpm. At the 3 gpm, the deterioration in the near-atomizer regions of the floor and right hand walls at the 1000 ppm concentration appears to be more significant than the minor improvements already seen for the 500 ppm concentration in the wall temperature profiles elsewhere. At the 4 gpm lime slurry flow rate, the wall wetting near the atomizer on the right wall was intensified by the higher surfactant concentration. Temperature profiles over the other walls did not change by increasing the surfactant concentration from 500 ppm to 1000 ppm. At the 5 gpm slurry flow, the floor wetting near the atomizer is intensified at the higher surfactant concentration. There are marginal effects attributable to surfactant concentration on the top and right walls. The left wall temperature profile is significantly improved at the higher surfactant concentration. At the 6 gpm slurry flow rate, which is of practical interest from a flue gas desulfurization viewpoint, the higher surfactant concentration (1000 ppm) improves the wall temperature profiles on the top, right, and left walls over those obtained at the 500 ppm additive concentration. However, the floor profiles are worsened by increasing the additive to 1000 ppm. At this flow rate, surfactant addition to the lime slurry appears to improve the wall temperature profiles on all sides except possibly the right wall. In the case of the right wall, the temperature profile corresponding to no additive appears to yield the best non-wetting characteristics.

17. See Figures 74 to 77. Earlier experiments conducted by Snaddon [6] at the GE Corporate Research and Development laboratories in Schenectady indicated that increasing the liquid flow rate through an atomizer hole leads to smaller particle sizes. The effect of variable number of atomizer holes, with and without surfactant addition to lime, and gas flow correction devices was investigated in the pilot plant. For the same lime slurry flow rate, the following variations were studied at a gas flow rate of 25 kcfm: (i) 8 atomizer holes, no additive to lime slurry, no gas flow devices (baseline), (ii) 8 atomizer holes, 500 ppm surfactant to lime slurry, and no gas flow devices, (iii) same as item (ii), but with 4 atomizer holes, (iv) 2 atomizer holes, 500 ppm surfactant addition to lime, and in the

Figure 74. Effect of surfactant concentration and number of slurry injection holes in atomizer wheel on Station 2 boundary layer temperatures for an inlet gas flow rate of 25 kacfm and a lime slurry flow rate corresponding to an outlet temperature of 236 F through the atomizer spinning at 14 krpm. The 13 in. airfoil, when used, was placed at 20° angle and 31 in. nose height. The aiflaps, when used, were set at their optimal nose positions

(a) Top

(b) Bottom

(c) Right

(d) Left

Figure 75. Same as in Figure 74, except for a lime slurry flow rate corresponding to a 233 F Station 2 outlet temperature.

Figure 76. Same as in Figure 74, except for a lime slurry flow rate corresponding to a 223 F Station 2 outlet temperature.

Figure 77. Same as in Figure 74, except for a lime slurry flow rate corresponding to a 212 F Station 2 outlet temperature.

presence of side flaps at the optimal positions as determined from earlier tests, and described earlier, and (v) same as item (iv), but with the airfoil at its optimal position as described in earlier tests. As experienced in the tests with surfactant addition, at the low lime slurry flow rates, the ceiling and left wall temperature profiles were not seriously affected by the variations listed above. However, the floor and right wall temperature profiles are sensitive to these variations. The floor profiles were improved by the 4-hole atomizer with the surfactant treated lime (variation (iii)). The right wall profiles are improved by both the 4-hole atomizer (variation (iii)), and the 2-hole atomizer with flaps (variation ((iv))). Only the 4-hole atomizer improved both the profiles on both (floor and right) walls. The same wetting patterns remain as the slurry flow rate is increased to about 6 gpm (gas outlet temperature about 210 F). Even at this lime slurry flow rate, the 4-hole atomizer with surfactant treated lime is beneficial to improving the wall temperature profiles on all sides of the duct. The 2-hole atomizer with flaps improves the profiles on the right, ceiling and left walls, but significantly degrades the profile for the floor. The 8-hole atomizer with surfactant treated lime significantly degrades the right wall profile, and the left wall profile slightly, but does not seriously change the top and left wall profiles.

Overall, the 4-hole and 2-hole atomizer in combination with the optimized 13 in. wing and airflaps, and operating with lime containing 500 ppm surfactant appear to provide nearly non-wetting operation. Severe wall wetting appears to be confined to only the right and left walls immediately adjacent to the atomizer.

18. See Figure 78. The effect of similar variations were also investigated at the 50 kcfm gas flow rate: (vi) 8-hole atomizer with 1000 ppm surfactant added to lime slurry, and no gas flow device, (vii) 4-hole atomizer with 500 ppm surfactant added to lime slurry and no gas flow device, and (viii) 2-hole atomizer with 500 ppm surfactant added to lime slurry and airfoil at 20° angle with the 31 in nose position. Only a single lime slurry flow rate (13 gpm) representative of realistic SO₂ removal efficiencies was investigated. At this high lime² slurry flow rate, the differences in the wall temperature profiles attributable to the variations listed above are small. Overall, at this gas flow rate, the 2-hole atomizer with airfoil and 500 ppm surfactant, and the 8-hole atomizer with 1000 ppm atomizer and no gas flow device appeared to yield warmer wall temperatures than the 4-hole atomizer with 500 ppm surfactant and no gas flow device. None of the variations eliminated the localized wetting spot directly opposite the atomizer on the right wall. However, the 2-hole atomizer combination (variation (viii)) did appear to alleviate a corresponding cold spot on the left wall. Overall, the 2-hole atomizer combination (variation (viii)) appeared to yield more favorable wall temperature profiles than the 8-hole atomizer combination (variation (vi)).

Figure 78. Same as in Figure 74, except for a lime slurry flow rate of 13 gpm corresponding to about a 190 F Station 2 outlet temperature.

Summary of Station 2 Wall Temperature Data--

The atomizer spinning at 14 krpm was found to yield the highest wall temperature profiles. At a gas flow rate of 50 kcfm, all wall temperatures are above 160 F, up to a water-only flow rate of 3.8 gpm through the atomizer spinning at 14 krpm with no gas flow devices upstream of the atomizer. Above this flow rate the ceiling near the atomizer shows heavy wetting. The right wall temperatures show a transition at low water flow rates. At a 1.9 gpm water flow rate, the right wall about 4 ft from the shows a temperature of 160 F. However with increasing water flow rate, this cold spot gradually shifts in the downstream direction. The floor stays the driest. Also the left wall temperature dips below 160 F only at the highest flow rate (4.9 gpm) tested. Under the same conditions, the wall temperatures with lime slurry are warmer than those with water, indicating possibly the generation of smaller droplets with lime than with water in the rotary atomizer. The lime flow rate before any wall temperature drops below 160 F is 6.6 gpm, which is about 50% more than observed with water alone. At 9 gpm lime slurry flow rate, the right wall shows evidence of severe wetting. The left wall is similarly wetted at a higher flow rate (11.2 gpm). As with water, the duct floor appears dry at all lime flow rates tested. Thus, it appears that wall wetting is not severe up to about half the design lime slurry flow rate (14 gpm at the design gas flow rate of 50 kcfm).

With water flowing through the atomizer at 14 krpm, the 24-in. wide wing produces wall temperature distributions not significantly different from those without the foil. This is probably because water droplets penetrate close to the walls and are not sensitive to diversion by flow control devices. However, in larger ducts, flow control devices are expected to have pronounced effects on droplet dispersion. With water, the nose position was optimized at 31 in. and the approach angle at 15°. The 24-in. wing gave slightly warmer wall temperatures than the 13 in. wing when both wings are identically oriented. Only the 13 in. wing was optimized with lime flow through the atomizer spinning at 14 krpm. At a lime flow rate of about 6 gpm, the wall temperature distribution with the 13 in. wing optimally oriented at 19° and a nose position of 29 in. was about 5-10° F warmer than those obtained without the wing. However, at higher lime slurry flow rates, the wing was not effective in eliminating the wall wetting observed on the right, left, and ceiling walls close to the atomizer. At the design lime slurry flow rate of 14 gpm the wall temperature profiles with the optimized 13 in. wing showed severe wall wetting of the right, left, and ceiling walls within about 8 ft from the atomizer. Similar results were obtained at the 25 kcfm gas flow rate.

The airflaps, in combination with the 13 in. wing, were found to improve the wall temperature profiles (i.e., increase the average wall temperature) up to a lime slurry flow rate of 6 gpm at the 50 kcfm gas flow rate. Above this flow rate, the onset of severe wetting could not be prevented with the addition of the airflaps. A right airflap position of 8.75 in. and a left airflap position of 5 in. were found to be optimal.

The effect of surfactant on the wall temperature profiles were investigated at the 25 kcfm gas flow rate. In general, up to a lime slurry flow rate of 6 gpm (corresponding to 12 gpm at the 50 kcfm gas flow rate), surfactant addition at the 500 ppm level was found to be optimal. Reducing the number of holes in the atomizer from 8 to 4 and 2 were found to benefit the surfactant enhancement of droplet confinement. The results with lime containing 500 ppm surfactant through 2 atomizer holes in the presence of the optimized 13 in. wing and airflaps gave slightly better droplet confinement than with the surfactant-containing lime through 4 atomizer holes. At the design gas flow rate of 50 kcfm and 13 gpm lime flow, operation of the atomizer with 2 holes and optimized wing and flaps gave the best droplet confinement as inferred from the wall temperature profiles. However, all of the innovations to promote droplet confinement, namely, airfoil, airflaps, surfactant addition to lime, and atomizer modification to run with 2 atomizing holes, were not effective in eliminating wall wetting of the right and left walls directly opposite the atomizer.

However, despite the difficulty in completely eliminating wall wetting in the pilot-scale ductwork, the above-described effort to study the influence of gas flow distribution devices and atomization characteristics on droplet dispersion (or confinement) will be extremely useful in optimizing droplet dispersion in full-scale ducts. In this situation, the droplet dispersion rather than droplet confinement will be the main concern. Further studies to enhance droplet dispersion in a large duct are essential to full-scale implementation of, and the commercialization of, the IDS technology.

SO₂ Removal Efficiency--

Station 1 SO₂ removal data has already been presented. Station 2 SO₂ removal efficiencies were measured for calcium to sulfur inlet molar² ratio (dry stoichiometric ratio) ranging from 0.4 to 1.5, and duct velocities in the range of 28.8 to 69.6 ft/s. The observed SO₂ removal efficiencies are shown as a function of the dry stoichiometric ratio, S, which is the ratio of moles Ca fed in the atomizer to the moles SO₂ entering the system, in Table 9 and in Figures 79 to 82. Detailed test information is provided in Appendix B. Figure 79 shows the effect of gas flow rate on the SO₂ removal efficiency taking place in the evaporation zone (1-sec gas² residence time) and the system (inlet to outlet). Figure 80 compares the removal taking place in the evaporation zone comprising 60 ft of duct measured from the atomizer location with that in the system (that taking place in the evaporation zone, ESP and inter-connecting ductwork). The removals in both the evaporation zone and in the system are seen to be nearly independent of the gas flow rate. An explanation for the independence of the SO₂ removal in the evaporation zone was provided in an earlier paper. Essentially, the SO₂ removal process either in a conventional DFGD system or in an IDS system occurs through the reaction between SO₂ and droplets containing suspended lime slurry. The wet surface of the droplets is essential for SO₂ dissolution. It can be shown that the SO₂ removal taking place during the period of droplet

TABLE 9 - STATION 2 (HORIZONTAL DUCT) SO2 REMOVAL DATA SUMMARY

TEST NO:	1	2	3	4	5	6	7	8	9	10
INLET GAS FLOW RATE, acfm:	24,764	23,207	24,840	49,285	49,828	50,492	53,884	52,804	50,950	48,353
INLET GAS TEMPERATURE, F:	325	325	323	336	335	336	339	334	335	335
OUTLET GAS TEMPERATURE, F:	224	231	214	298	284	265	258	248	224	203
DRY SR, FRESH LIME:	0.44	0.49	0.67	0.16	0.29	0.50	0.65	0.74	1.11	1.33
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	0.44	0.49	0.67	0.16	0.29	0.46	0.65	0.74	1.11	1.33
SO2 REMOVAL EFFICIENCIES:										
1s (EVAPORATION ZONE)	25.1	9.0	26.3	3.3	1.2	6.0	20.3	21.4	32.9	42.2
DRIFT ZONE (% OF INLET)	.0	.0	.0	.0	.0	4.1	.0	1.5	.6	1.3
ESP (% OF INLET)	2.3	11.2	3.3	2.5	8.9	6.4	1.2	4.1	.9	7.0
SYSTEM	26.8	19.2	28.7	5.7	9.9	15.7	21.2	25.8	33.9	46.9
ESP POWER, kW	.0	.0	.0	37.8	36.0	34.8	39.4	42.9	41.8	42.1
OUTLET OPACITY, %				14.7	15.7	1.6				
TEST NO:	11	12	13	14	15	16	17	18	19	20
INLET GAS FLOW RATE, acfm:	26,649	26,283	51,962	51,875	27,006	48,921	26,149	26,688	26,290	54,330
INLET GAS TEMPERATURE, F:	336	335	358	345	332	367	346	344	338	361
OUTLET GAS TEMPERATURE, F:	243	237	240	229	240	225	242	210	240	250
DRY SR, FRESH LIME:	.48	.89	1.13	1.17	1.16	1.44	1.24	1.53	1.15	1.01
DRY SR, OFF-PRODUCT:	0	0	0	0	0	0	0	0	0	0
DRY SR, FRESH LIME+OFF-PRODUCT:	.48	.46	1.13	1.17	1.16	1.44	1.24	1.53	1.15	1.01
SO2 REMOVAL EFFICIENCIES:										
1s (EVAPORATION ZONE)	21.4	30.2	30.9	26.1	31.3	43.6	32.4	47.1	36.2	35.6
DRIFT ZONE (% OF INLET)	.0	1.9	.0	.0	9.0	1.0	1.5	.0	.0	2.8
ESP (% OF INLET)	1.4	7.6	10.4	15.7	4.9	6.6	6.1	5.0	4.2	2.3
SYSTEM	21.1	36.8	38.0	37.6	40.6	47.9	37.5	49.8	38.8	38.9
ESP POWER, kW	40.1	39.9	41.0	41.7	40.8	42.0	38.6	41.9	40.0	35.9
OUTLET OPACITY, %				2.0	.9	6.0	2.5	1.6	2.7	
TEST NO:	21	22	23	24	25	26	27	28	29	
INLET GAS FLOW RATE, acfm:	26,729	25,289	50,561	47,481	49,814	49,562	48,604	60,413	61,722	
INLET GAS TEMPERATURE, F:	332	341	355	347	362	344	344	364	357	
OUTLET GAS TEMPERATURE, F:	237	269	254	249	230	229	228	252	241	
DRY SR, FRESH LIME:	.57	1.27	.97	1.46	.62	1.38	.57	1.18	.58	
DRY SR, OFF-PRODUCT:	0	0	0	0	0	0	0	0	0	
DRY SR, FRESH LIME+OFF-PRODUCT:	.57	1.27	.97	1.46	.62	1.38	.57	1.18	.58	
SO2 REMOVAL EFFICIENCIES:										
1s (EVAPORATION ZONE)	24.2	36.8	36.5	34.8	31.5	36.1	25.7	29.9	28.8	
DRIFT ZONE (% OF INLET)	3.1	.0	1.6	.0	.0	4.6	4.1	10.0	3.5	
ESP (% OF INLET)	6.8	10.8	1.4	21.0	3.6	1.7	1.0	2.5	.0	
SYSTEM	31.5	43.6	38.4	48.5	33.9	40.1	29.5	38.6	30.8	
ESP POWER, kW	34.1	37.9	41.1	42.6	35.7	43.3	43.4	41.7	42.3	
OUTLET OPACITY, %	1.3	4.1	5.0	3.9	2.2	2.0	1.9	2.7	2.4	

Figure 79. Effect of inlet gas flow rate on the Station 2 SO₂ removal efficiencies in: (a) evaporation zone, and (b) system.

Figure 80. Station 2 SO₂ removal efficiencies attributable to the evaporation, drift, and ESP zones.

Figure 81. Comparison of SO₂ removal efficiencies in Station 2 evaporation zone with DFGD model.

Figure 82. Comparison of SO₂ removal efficiencies in Station 2 system with DFGD model.

Figure 83. Effect of gas flow rate (or residence time) on NO_x removal efficiency during Station 2 dry recycle precursor tests.

evaporation is independent of initial droplet size and droplet velocity, provided complete droplet evaporation is obtained (see Equation 31 derivation). The results shown in Figure 79 confirm the conclusion of the previously presented model. It is apparent that droplet evaporation must be complete within the 60 ft duct even at the highest flow rate tested (i.e., in roughly 1 second gas residence time). Figure 79 shows two sets of linear trends. The first trend is associated with runs having a 40-55 F range in the approach to saturation at the end of the evaporation zone. The second trend is associated with higher approach temperatures. The DFGD model developed earlier provides a means of unifying data with different stoichiometries and approach temperatures in a single curve. This model predicts a linear relationship between $-\ln(1-e_1)$ and $S \ln[(T_i - T_{as}) / (T_f - T_{as})]$ (see Equation 47). Figure 79 shows only a nearly linear trend expected from the model. A non-linear least squares fit to the data in the form:

$$-\ln(1-e_1) = a \{S \ln[(T_i - T_{as}) / (T_f - T_{as})]\}^b \quad -(48)-$$

yields lower residuals than the linear fit. The non-linear fit better represent the pilot data, but cannot be theoretically justified at the present time. The increasing droplet/gas momentum transfer with increasing stoichiometric ratio, increasing wall wetting tendency with decreasing approaches to saturation, SO_2 removal by wall deposits, and non-uniform droplet/gas mixing are probably factors which contribute to the departure from the model-predicted linear trend. Figure 80 compares the dependence of the SO_2 removal taking place across the drift zone (post-evaporation zone duct + ESP) with that taking place across the evaporation zone. It is surprising that a plot based on Equation 48 for the system removal (Figure 82) leads to a remarkably close fit with the experimental data (in fact, the regression coefficient for the fit to the system data is higher than that for the 1-sec (evaporation zone) data (Figure 82). There is no theoretical justification for this observed empirical relationship for the system removal. The factors listed earlier to explain the slight non-linearity observed even for the evaporation zone removal need to be included in developing a model which can explain the observed trend in the system removal. Demonstration of the 50% SO_2 removal proof-of-concept target for a Ca to S ratio of 1.47 was verified experimentally at a 40 F approach to saturation and at the design gas flow rate. The projected Ca to S ratio of 1.61 for a 60 F approach temperature could not be verified experimentally due to the inability to transport the required lime in the lower evaporation water flow rate.

Off-Product---

Table 10 shows a comparison of the compositions of off-product samples collected from duct and ESP locations after several Station 1 and Station 2 SO_2 removal tests. Duct samples display significantly higher carbonate mass fractions than ESP hopper samples. This indicates that the unspent lime in duct deposits continue to react with the flue gas CO_2 to increase in carbonate content. On the other hand, the ESP samples, being removed from the main flue gas flow probably react much slower to produce the carbonate. Some of the carbonate is formed during the flight of

TABLE 10. IDS OFF-PRODUCT COMPARISON

DATE	STATION	LOCATION	Ca/S	% Eff.	Moisture %	Acid Insoluble %	% Hydroxide MAF as $\text{Ca}(\text{OH})_2$	% Sulfur MAF as $\text{CaSO}_3 \cdot 1/2\text{H}_2\text{O}$	% Calcium MAF as Ca	% Carbonate MAF as CaCO_3
4/1/87	I	Duct	0.7	20	11.5	40.6	9.9	28.8	39.2	48.6
	I	ESP	0.7	20	5.6	54.0	29.8	27.6	35.0	16.4
8/10/87	I	Duct	0.75	35	21.3	31.3	3.6	50.4	30.4	33.3
	I	ESP	0.75	35	0.1	43.5	39.9	41.3	37.5	8.5
10/7/87	II	Duct	0.54	17	10.0	27.1	28.5	36.8	39.2	38.7
		ESP	0.54	17	0.0	58.3	13.5	25.3	16.2	11.8
10/17/87	II	Duct	1.40	47	9.3	16.4	29.8	30.4	38.9	41.5
		ESP	1.40	47	0.0	49.6	18.7	33.4	21.4	3.5
12/16/87	II	Duct(wall)	1.04	39	14.1	20.6	27.0	21.3	36.4	33.7
		Duct(floor)	1.04	39	43.8	25.2	51.0	18.4	39.7	18.5
		ESP	1.04	39	0.2	45.0	33.4	27.5	31.0	9.1

slurry droplets in the gas stream in the same manner as sulfite is formed by reaction with SO_2 . The lower CO_2 dissolution rate (in comparison with SO_2) is partly made up by the nearly four-fold increase in the CO_2 concentration. As a result of this combination, CO_2 does compete with SO_2 for lime to limit lime utilization for the desulfurization reaction. The carbonate content of the ESP samples probably reflect this limitation.

The presence of carbonate in the off-product provides a mechanism for the enhancement of SO_2 removal in the presence of dry recycle. It is possible for the carbonate in the recycled off-product in the presence of flue gas moisture to form sulfite in a dry reaction:

Further work is required to assess the importance of this mechanism. Of course, unreacted lime in the off-product could also have the same enhancing effect

SO_2 Removal By Station 2 Wall Deposits---

SO_2 removal soon after shut-off of lime slurry and dilution water to the atomizer are given in Appendix C. The SO_2 removal attributable to the walls is less than about 5%.

Dry Recycle---

Experiments conducted at GE's Corporate Research and Development Laboratories (CRD) showed significant NO_x removal by DFGD off-product in bench-scale apparatus operated in batch mode. These experiments indicated the possibility of effecting NO_x removal in the IDS system through dry injection of off-product in the ductwork. Based on these laboratory experiments, the capability for pneumatically injecting off-product from a storage silo was included in the pilot plant design, as described earlier. A suitably sized air compressor, accompanying venturi eductor for entraining the off-product in compressed air, and piping for delivering the entrained solids to the injection point are components added to the pilot plant. The effect of injecting dry off-product, obtained from an earlier IDS operation at the 50% SO_2 removal efficiencies, was investigated over a range of inlet gas flow rates, inlet gas temperatures, lime slurry flow rates, and dry recycle flow rates. The off-product was injected at the slipstream inlet to the pilot plant well ahead of the slurry atomization zone.

The favorable effect of dry recycle on the NO_x removal, as indicated by the original CRD tests, was evaluated with respect to gas flow rate, lime slurry feed rate, and dry recycle injection rate. Each dry recycle test is preceded by a precursor test during which waste product is collected for use in the succeeding test with dry re-injection. All precursor tests were run under the same conditions of lime and water feed rates. The off-product from the pre-cursor tests were stored in the ash silo for subsequent use in tests with dry recycle. The SO_2 and NO_x removals were monitored during these precursor tests, and are presented in Table 11 and

TABLE 11 - NOx REMOVAL DATA SUMMARY

TEST NO:	P R E C U R S O R T E S T S						T E S T S W I T H D R Y I N J E C T I O N					
	1	2	3	4	5	6	1	2	3	4	5	6
INLET GAS FLOW RATE, acfm:	28,747	28,404	29,451	56,227	56,524	56,956	25,882	28,621	28,106	57,004	54,663	28,529
INLET GAS TEMPERATURE, F:	339	340	355	355	357	361	328	335	349	342	344	326
OUTLET GAS TEMPERATURE, F:	203	207	223	221	222	226	230	223	227	217	222	199
DRY SR, FRESH LIME:	0.99	01.00	01.01	01.03	01.06	0.94	0.00	0.51	0.70	0.53	0.73	1.10
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00	0.78	0.33	0.09	0.23	0.04	0.15
DRY SR, FRESH LIME+OFF-PRODUCT:	0.99	01.00	01.01	01.03	01.06	0.94	0.78	0.84	0.79	0.76	0.77	1.25
SO2 REMOVAL EFFICIENCIES: @ 1s (EVAPORATION ZONE) SYSTEM	44.5	46.0	38.9	43.6	44.1	42.0	16.5 24.2	31.2 35.7	40.8 41.9	30.5 34.5	34.1 38.7	51.1 58.0
SYSTEM NOx REMOVAL EFFICIENCY: @ 1s (EVAPORATION ZONE) SYSTEM	8.2	8.3	8.7	3.0	5.1	3.4	8.0 13.4	3.0 10.8	4.0 12.2	3.0 12.6	7.0 13.4	2.0 17.9
ESP POWER, kW	38.20	40.23	43.74	31.92	40.55	39.61	40.60	39.42	41.54	34.32	39.82	38.57
OUTLET OPACITY,%	2.8	4.6	1.4	4.3	6.1	7.2	2.2	3.4	.5	6.2	9.4	9.7

Appendix D. SO_2 removals during the precursor tests are seen to be by and large constant, since the gas flow rate is the only significant variant in this set of tests, to which the SO_2 removal was shown earlier to be insensitive. The NO_x removal, on the other hand, does show a dependence on gas flow rate, and hence on residence time, as seen in Figure 83. Most of the NO_x removal takes place after droplet evaporation is completed. In contrast with the mechanism of SO_2 removal, NO_x (mostly NO) removal is postulated to take place by oxidation of the calcium sulfite resulting from the desulfurization reaction, as:

The reaction is thought to be a dry reaction, meaning that no wet interface is required. The chemical analyses of the product obtained from the precursor tests are shown in Figure 84. These results favor the above-postulated mechanism because of the presence of sulfite in the re-injected product, and the absence of nitrite or nitrate in any of the post-atomizer samples. The residence-time dependence of the NO_x removal taking place in the absence of re-injected dry product probably indicates that the global rate of NO_x removal is constant with respect to time under these conditions, the rate constant itself probably depending on approach temperature, lime stoichiometric ratio, and other flue gas and fly ash properties.

The results of tests to ascertain NO_x removal in the presence of dry recycle are plotted in Figures 85 and 86. Test details are tabulated in Appendix D. Off-product from a pre-cursor test was injected at the inlet of the Pilot Plant slipstream which is about a 150 ft upstream of the Station 2 atomizer. The recycled ash is entrained in the slipstream gas for about 2.5 seconds before reaching the atomizer. There is, surprisingly, little influence on the NO_x removal attributable to the recycle rate or total available time. Also, the dependence of the NO_x removal on the residence time observed for the precursor tests appears to be absent in the presence of dry recycle. Figure 86 attempts to correlate the NO_x removal to the SO_2 removal. The large scatter of the few data points shown does not appear to define a strong correlation. Based on the mechanism discussed above, a strong correlation between the two removals would be expected, since higher SO_2 removal will result in higher sulfite formation which in turn would be expected to result in higher NO_x removals. Figure 87 compares the SO_2 removal with dry recycle on the basis of Equation (48). While SO_2 removal is strongly related to the slurry feed rate and approach temperature, the NO_x removal is at best only weakly correlated to these variables. This is not unexpected since the NO_x removal reactions are expected to be dry reactions not requiring a wet interface, and therefore do not conform to the basic assumptions leading to the derivation of Equation (47) on which Equation (48) is based. Figure 87 shows that as compared to single pass slurry treatment (no dry recycle), the Ca to S ratio required for 50% SO_2 removal is reduced from 1.5 to 1.0 by the very presence of dry recycle at a nominal rate of 4 gr/acf. The SO_2 removal rate enhancement by the dry recycle appeared to be independent of the dry recycle flow rate in the range of 4 gr/acf to 18 gr/acf. A similar enhancement of SO_2 removal through wet recycle of off-product has been reported in dry flue gas Desulfurization (DFGD) systems.

57.5 Kacfm, 58 deg F approach, Ca/S = 1.1, SO₂ off = 38%

Figure 84. Typical Station 2 off-product composition in the presence of lime slurry atomization in duct.

Figure 85. Effect of dry recycle mass flow rate on Station 2 NO_x removal efficiency.

Figure 86. Correlation between Station 2 system SO2 and NOx removal efficiencies in the presence of dry recycle.

Figure 87. Comparison of Station 2 SO2 and NOx removal efficiencies in the presence of dry recycle, with DFGD model.

Although NO_x reductions of 11 to 18% were observed, the average value of 13% is statistically most probable across a four-fold range of recycle rates tested. No correlations between NO_x removal, and SO_2 removal, lime feed rate, or total lime content (including available lime² in recycle feed), are apparent. The identification of process parameters influencing NO_x removal, and the optimization of the NO_x removal with respect to these process parameters is still open. The question whether the NO_x removal can be optimized to achieve the 50% goal desired for acid rain^x precursors is left unanswered by the present pilot effort.

Figure 88 compares the dry recycle enhanced SO_2 removal using the least-squares fits to Equation (36) of the SO_2 removal data. The data points in this figure are calculated from Equation (48) using the constants shown in Figures 81 and 82. As a rule of thumb, the SO_2 removal efficiency in the evaporation zone alone in the presence of dry recycle matches the system efficiency observed without recycle. The stoichiometric ratio used on the abscissa does not include the available in the recycle feed. The finite removals seen at 0 stoichiometric ratio indicates the effectiveness of the available lime in the dry recycle feed. However, the invariability of the SO_2 removal also to the dry recycle feed rate (as seen in Figures 85 and 86) is surprising. The multiplicative temperature factor used in Figure 88 is, under typical conditions, about 1.7 for a 40 F approach to saturation, and about 1.3 for a 60 F approach. Thus, at a stoichiometric ratio of 1, the abscissa is 1.7 at a 40 F approach, and 1.3 at a 60 F approach. The system removal efficiency in the presence of dry injection, at unit stoichiometric ratio, is seen from Figure 88 to be about 54% at 40 F approach, and about 47% at 60 F approach. The corresponding efficiencies in the absence of dry recycle are 43% and 36%. In the absence of dry recycle, a dry stoichiometric ratio of about 1.5 is required at the 40 F approach temperature. Thus, dry recycle, in addition to enhancing NO_x removal, also provides the advantage of about 33% saving in lime costs. However, the additional capital and operational costs associated with dry recycle needs to be compared with the lime savings, before implementing dry recycle.

Comparison of Station 1 and Station 2 SO_2 Removal Performances---

In Station 1, the droplet distributions in horizontal planes downstream of the atomizer will be approximately symmetric about the atomizer axis (the departure from cylindrical symmetry due to effects of the right angle turn into Station 1). In contrast, when atomizer rotation is included, there is no symmetry in the droplet distribution in Station 2. Thus, extent of droplet dispersions will be expected to be different in the two atomizer configurations. Comparison of the SO_2 removal efficiencies in the two stations can yield an indication of the effectiveness of droplet dispersion in each station. Figures 89 and 90 compare the SO_2 removal efficiencies observed in Stations 1 and 2 on the basis of the least-squares fit suggested by Equation (36) and shown in Figures 51, 81 and 82. Figure 89 compares Station 1 removal with Station 2 removal without dry recycle. The removals in both stations, for low stoichiometric ratio or high approach temperatures (in effect, low slurry

Figure 88. Effect of dry recycle on Station 2 SO₂ and NO_x removal efficiencies.

Figure 89. Comparison of Station 1 and Station 2 SO₂ removal efficiencies in the absence of dry recycle.

feed rates) are in close agreement. However, with increasing stoichiometric ratio or decreasing approach temperatures (or increasing lime slurry feed rates), the difference between the system removals in the two Stations increases. The Station 1 removal efficiency is consistently higher than that in Station 2 (except, as mentioned earlier, at low slurry feed rates where the two removals are nearly equal). With increasing lime slurry flow rate, the difference between the Station 1 and Station 2 system removals increases. The rate of increase of the SO_2 removal efficiency with increasing X ($X = S \ln[(T_i - T_{as})/(T_f - T_{as})]$), remains relatively steady in Station 1, whereas there is tendency for the Station 2 SO_2 removal to flatten out with increasing X .

The difference between Station 1 and Station 2 SO_2 removal efficiencies in the evaporation zone also increases with increasing X , but not as drastically as the difference in the system removals. The rates of increase of the evaporation zone SO_2 removal efficiency in both stations are nearly the same at the intermediate values of X .

The tendency of the Station 2 system removal efficiency to flatten out with increasing X may be the result of the increasing wall wetting tendency with increasing lime slurry feed rates discussed earlier. The Station 2 wall wetting appears to seriously limit the off-product concentration in the gas stream entering the drift zone and the ESP. In contrast, the steady increase of the Station 1 system removal with increasing X is indicative of less severe wall wetting and better off-product carry over into the Station 1 drift zone and the ESP even at high lime slurry flow rates.

At a 40 F approach temperature and unit stoichiometric ratio, the Station 1 system removal is about 52%, which is only slightly smaller than the 54% Station 2 efficiency in the presence of dry recycle, but is significantly higher than the 43% Station 2 efficiency in the absence of dry recycle.

Figure 90 compares Station 1 SO_2 removal efficiency with that observed in Station 2 in the presence of dry recycle. Again, Equation (36) together with the constants derived from least-squares analyses of the experimental data shown in Figures 51 and 87 have been used in Figure 90 to represent the experimental data. The comparison shown in Figure 90 is useful to assess the SO_2 removal effectiveness of each station. At low values of X close to 0, the Station 2 performance with dry recycle is significantly better than that seen in Station 1. However, with increasing X (or lime slurry feed rates), the difference between the performances in the two stations decreases. In fact, beyond about $X=1$, the differences between the Station 2 and Station 1 performances in both the evaporation zone and the system, appear to be nearly constant with respect to X .

Station 1 performance is seen to be only slightly below the dry recycle enhanced performance of Station 2. At the reference 40 F approach, and unit stoichiometric ratio, the difference between the Station 1 performance without dry recycle, and Station 2 efficiency with dry recycle is only about 2 or 3%.

Figure 90. Comparison of Station 1 SO₂ removal efficiency (in the absence of dry recycle) with Station 2 SO₂ removal efficiency (in the presence of dry recycle).

The agreement between the Station 1 and Station 2 performances without dry recycle (see Figure 89) is indicative of identical behavior in both stations when wall wetting is absent. The differences between the performances of the two stations arises from the wall wetting extent, which in turn appears related to the increasing turbulence in the duct with increasing liquid-to-gas momentum ratio. It appears that the extent of turbulent energy dissipation in Station 2 geometry is higher than that in Station 1 geometry for the same liquid and gas flow rates. This subject will be dealt at greater length in a later section.

The above comparisons of the SO_2 removal performance between the two stations are valid only for the pilot scale duct work. They cannot be arbitrarily extended to be applicable in full-scale ducts in which wall wetting is likely to be totally absent. In this case both stations would be expected to perform equally.

Precipitator Performance---

Although scheduling difficulties prevented precipitator characterization by iso-kinetic sampling, other studies point to the suitability of electrostatic precipitators for In-Duct Scrubbing service.

Station 2 precipitator studies first focussed on voltage to current (V-I) relationships. Data presented in Figure 91 compares a flyash only case (inlet loading of 3.8 gr/acf) with a slurry addition case (inlet loading of 3.1 gr/acf). No notable differences in the V-I curves are apparent for the outlet and center fields. Only the inlet field shows a significant increase in secondary voltage resulting from the higher inlet particulate loading. As progressively higher inlet loadings are encountered, it is expected that the V-I relationships for the center fields will also become increasingly influenced.

Precipitator parametric data for a typical slurry injection test is also presented in Table 12. Collected volumes confirm that more than 92% of the material is collected in the inlet hopper. V-I data indicates that the preponderant effect is absorbed by the inlet field with reduced current in the second field probably resulting from the loading effects. Resistivity and particle size data are also included in Table 12 for reference.

Opacity data taken during testing at Station 1 are presented in Table 13 and in Figure 92. Figure 92(a) shows the expected inverse relationship between opacity and SCA in the form of a $\log(\text{Opacity})$ Vs. SCA graph. The data in this figure were obtained by varying the gas flow rate as well as by varying the number of energized ESP fields. Some of the scatter in the data shown in Figure 92(a) are due to temperature variations which change the dust concentration, and consequently the opacity, without an accompanying change in the dust mass flow rate.

Figure 91. Effect of Station 2 lime slurry injection on ESP V-i curves: (a) no lime slurry, and (b) 9.3 gpm lime slurry flow rate.

TABLE 12 - IDS PILOT PLANT PRECIPITATOR DATA FOR TYPICAL STATION 2 SLURRY INJECTION TEST

57.5 Kacfm, 59 deg F approach, Ca/S = 1.1, SO₂ eff = 39%

<u>HOPPER</u>	<u>FIELD</u>	<u>VOLTAGE (KV)</u>	<u>CURRENT (ma)</u>	<u>COLLECTED VOLUME (FT³)</u>	<u>RESISTIVITY OHM-CM @ 190°F 10%v H₂O</u>	<u>MEAN PARTICLE SIZE (MICRONS)</u>
Inlet	D	43.4	100	36	5.5×10^{11}	8.6
	C	37.6	238			
Center	C	37.6	238	2	4.1×10^9	14.8
	B	36.8	320			
Outlet	B	36.8	320	1	6.6×10^9	12.5
	A	34.7	319			

TABLE 13. IDS PRECIPITATOR CHARACTERIZATION SUMMARY

DATE/TIME	LIQUID FLOW GPM	FLUE GAS FLOW ACFM	SYSTEM INLET TEMP. °F	ESP INLET TEMP. °F	ESP OUTLET TEMP. °F	SCA (NOMINAL) FT ³ /1000 CFM	OPACITY PERCENT (%)
4-2-87 11:18	-0-	47734	326	315	241	-0-	73
11:32	-0-	45698	327	320	247	400	2.58
11:52	-0-	48884	327	323	281	200	10.1
12:10	3.65 (W)	49379	329	259	256	200	14.9
12:31	2.92 (W)	50509	328	267	253	200	14.9
13:18	1.55 (W)	49807	332	294	270	200	16.2
13:46	1.56 (W)	25250	330	268	254	400	4.81
13:58	-0-	24309	329	309	255	400	4.91
14:08	3.70 (W)	25261	327	228	249	400	5.47
14:19	1.99 (S)	24636	329	270	246	400	6.63
14:25	1.70 (S)	28463	329	273	248	-0-	91.0
14:46	1.95 (S)	25989	327	271	246	400	5.51
15:07	3.97 (S)	25035	326	227	236	400	6.68
15:49	5.71 (S)	26673	327	194	213	400	14.55
16:38	5.69 (S)	28166	329	187	190	600	4.00
16:50	5.67 (S)	24752	326	185	186	800	3.02
17:28	5.51 (S)	25190	325	188	185	800 (A)	1.24
17:41	5.53 (S)	28017	324	186	184	400 (A)	3.64

A = AUTOMATIC PRECIPITATOR CONTROL
 S = LIME SLURRY FEED 19.7% SOLIDS BY WEIGHT
 W = WATER FEED

Figure 92. Effect of (a) SCA, and (b) dry recycle feed rate, on ESP outlet opacity.

□ $T(1a)=316-318\text{ F}$
 × $T(1a)=167-207\text{ F}$
 ▽ DRY RECYCLE
 ● PRECURSOR

FIGURE 92(c).
Opacity dependence
on ESP power at
25 kcfm gas flow
rate.

□ $T(1a)=257-344\text{ F}$
 × $T(1a)=169-172\text{ F}$
 ▽ DRY RECYCLE
 ● PRE-CURSOR

FIGURE 92(d).
Opacity dependence
on ESP power at
50 kcfm gas flow
rate.

Opacity data taken during testing at Station 2 are presented in Figures 92(b), 92(c), and 92(d). The influence of dry recycle on the precipitator efficiency was also investigated. The results are summarized in Figure 92(b). Although the few data points are scattered, a trend of increasing opacity with increasing dry recycle rate (indicated as an effective grain loading) is apparent.

Figures 92(c) and 92(d) summarize the effect of precipitator secondary power on opacity at nominal inlet gas flow rate of 25,000 and 50,000 cfm. Points on these two curves fall into four categories: (i) tests at high outlet temperatures (or high approaches to saturation) without dry recycle, (ii) tests at 50 to 70 F approach to saturation without dry recycle (iii) dry recycle precursor tests (for collecting off-product to be subsequently dry-recycled) at 50 to 70 F approach to saturation, and (iv) tests at 50 to 70 F approach to saturation with dry recycle. There is no process difference between categories (ii) and (iii). They are distinguished purely as a means to discern effects of dry recycle on ESP performance by comparison with ESP performance during only the immediately preceding tests having no dry recycle (precursor tests).

ESP performance is known to be influenced by the ESP inlet gas flow rate, inlet gas temperature, the inlet particulate loading, and the size and electrical characteristics of the particulate. The inlet gas flow rate changes the ESP's Specific Collecting Area (SCA) defined as the ratio of the gas flow rate, expressed in kcfm, and the ESP collecting plate area, expressed in square ft. The ESP collection efficiency improves with increasing SCA or decreasing gas flow rate (for the same plate area). This fact is exemplified in Figures 92(c) and 92(d). Most of the opacity levels at the 25 kcfm gas flow rate are below 4% while most of the opacity levels measured at the 50 kcfm gas flow rate are below only about 7%. The higher opacity at the higher gas flow rate is attributable to the SCA effect.

Higher ESP inlet gas temperature is seen to result in higher opacity at both gas flow rates studied. Higher ESP inlet gas temperature affects ESP performance adversely through higher inlet flow rate (for the same mass flow rate of gas), and through higher resistivity, assuming surface conduction of electricity through particulate layers on the collecting plates (for the surface conduction mechanism, resistivity increases with increasing temperature). The tests conducted with low humidification (or higher ESP inlet temperature) indicate wide variation over a small change in ESP secondary power. This variation suggests rapping reentrainment losses as the main mechanism of ESP performance deterioration at the higher inlet gas temperatures.

Figures 92(c) and 92(d) do not appear to display strong effects attributable to variations in ESP inlet particulate loading. The opacity vs. power data for tests with dry recycle fall in with points corresponding to no recycle. This fact suggests that the electrical properties especially the resistivity) of the fly ash and of the off-product from the lime reaction with SO_2 are favorable for collection in an ESP. Also, dry recycle does not appear to alter the electrical properties of the particulate entering the ESP.

The overall trend of opacity vs. ESP power are similar at both gas flow rates. At the 50 kcfm gas flow rate, the opacity displays a decreasing trend in the range between 7% to 2% with increasing ESP power in the range between 39 to 42 kW. Similarly, at the 25 kcfm gas flow rate, the opacity decreases in the range between 3% to 1% with increasing ESP power in the same 39 to 42 kW range. This decrease in opacity (or increase in ESP particulate collection efficiency) with increasing ESP power is expected due to increased particle charging and collection rates, and decreased particle reentrainment from the collecting plates. The above trend for decreasing opacity with increasing ESP power appears to be a characteristic of ESP operation under IDS process conditions and will provide a process rationale for implementing ESP power-saving control to automatically reduce ESP power to maintain a desired opacity level.

Figures 92(c) and 92(d) also show a weaker trend of increasing opacity with increasing ESP power below 36 kW at 50 kcfm gas flow and below 38 kW at 25 kcfm gas flow. The reduced power levels are mainly due to reduced current and voltage levels in the outlet TR set (TR set D). The reduced power in the outlet TR set appears due to dust buildup in the collection plates toward the ESP outlet.

The electrostatic precipitator data discussed above indicates stable and predictable performance.

5.0 COMPUTER FLOW MODELING

The discussions in the previous sections indicated that the wall wetting observed in both stations was nearly absent at lime slurry flow rates up to about half the design value required for a 60 F approach to saturation. At design lime slurry flow rates, the interaction between the lime slurry droplets, whose momentum is comparable to that of the gas, and the gas flow is highly turbulent. It is likely that the high turbulence of this droplet/gas momentum exchange is responsible for the wall wetting observed at the high lime slurry flow rates. Figure 32 compares the droplet momentum with that of the gas as a function of the atomizer angular speed and the liquid flow rate. The droplet/gas momentum ratio at the design liquid flow rates is close to 40%, and it appears the turbulence created by such a large momentum transfer within the confines of a 50 in. wide duct is too large for the largest droplets, which were calculated to just reach the duct wall in a normally turbulent flow, to escape wall impaction.

It is conceivable that the duct size could be sufficiently enlarged so as to accommodate the high momentum transfer occurring at the design gas and slurry flow rates without any wall wetting. This question was pursued with the aid of some two-dimensional flow modeling using the FLUENT. The following geometries were modeled in two dimensions for the design gas and liquid flow rates:

- (i) 50-in diameter duct with swirl (angular momentum) representative of Station 1 with a uniform inlet gas profile,
- (ii) a modified Station 1 duct with swirl having an expanded 70-in diameter duct for the first 20 ft and 50-in duct for the remaining 40 ft with an abrupt transition between the two duct sections,
- (iii) a 50-in wide horizontal duct representative of Station 2,
- (iv) a similar but expanded 70-in wide horizontal duct, and
- (v) an expanded 70-in wide duct for the first 20 ft followed by 40 ft of 50-in wide duct.

The 2-dimensional extent of the simplified modeling effort was focussed on learning about the influence of droplet/gas mixing parameters on droplet penetration with tacit knowledge that such penetration is not strongly influenced by the duct geometry. The 2-dimensional geometry is limited in the case of the Station 1 because the effect of the right angle turn into the Station 1 inlet is ignored. However the inclusion of angular momentum exchange is a positive factor in the analysis. The 2-dimensional simulation of the horizontal station is more limited in focus. The focus is only on direct droplet penetration to the duct walls. In this case, the confining effects of the horizontal walls on the fluid flow and droplet trajectories is ignored since only a horizontal duct of infinite vertical extent is modeled. The atomizer too is assumed to have an

infinite vertical extent. Despite the limitation of the simplified geometry used, it is expected that the direct droplet penetration data will be sufficient to determine the minimum duct diameter required to totally alleviate wall wetting.

In the discussions which follow, the right and left sides of the duct are referenced with respect to sighting in the direction of gas flow. The atomizer rotation is counter-clockwise when viewed from the top of the duct.

Case 1 - 50-in Wide Horizontal Duct

Figure 93 shows the 2-dimensional finite difference grid used in the computation. The 50 in. wide by 40 ft long duct is spanned by a 25 X 60 grid. The 60 finite divisions dividing the 40 ft of duct length have variable spacing. The finite difference along the duct length increases in geometric progression both upstream and downstream of the atomizer. This variable finite difference scheme is used to Since droplets are moving at their fastest velocities near the atomizer, the more grids are used to define the atomizer and its immediate vicinity in order to improve resolution. Table 14 shows the gas and liquid conditions used in the computation, while Figure 94 shows the manner in which the atomizer's continuous droplet injection points are approximated by eight injection points in the simulation. In the horizontal configuration, droplets are projected at all angles with respect to the direction of gas flow. Droplets emerging from the right side of the atomizer (looking in the direction of gas flow at the atomizer rotating in the counter-clockwise direction) are projected in a direction parallel to the gas flow. In the same way, droplets emerging from the left side of the duct are moving opposite to the gas flow. The droplets from the front and rear ends of the atomizer are at right angles to the atomizer. The result of the droplet/gas mixing in this case results in a reduction of the axial gas velocity on the left, an increase of the axial gas velocity on the right. The momentum component at right angles to the gas flow resulting from droplets emerging from the front and back sides of the atomizer, cause transverse velocity changes. The transverse velocity component is highest on the right side as the counter-clockwise rotation of the atomizer tends to diver more gas toward the right side. As a result of this diversion, the absolute pressure lowering on the right side near the atomizer is the highest.

Figure 95 shows the mean trajectories of droplets with various diameters. The 95 μ m diameter was assumed to be the largest. The 50-in width of the duct was based on the 95 μ m droplet just impacting the wall when the ejected by the atomizer at a design velocity of 540 ft/s. The mean droplets are the averages of several random trajectories shown in Figure 96 that droplets follow when flowing in a turbulent flow field. The mean trajectory for the 95 μ m droplet moving toward the right wall just hits the wall under the simulated flow conditions, whereas the mean trajectory moving toward the left wall just misses the left wall. The random trajectories plotted in Figure 96 do not appear to show the dissimilarity between the right and left trajectories. However, the mean trajectories are representative of large numbers of random trajectories

TABLE 14. IDS PILOT PLANT FLOW MODELING PARAMETERS

INLET CONDITIONS:

GAS FLOW RATE = 50,000 CFM @ 350⁰F

SLURRY FLOW RATE = 9 GPM

DROPLET SIZE DISTRIBUTION = ROSSIN-RAMMLER
(32 MICRON MEAN, 1.61 WIDTH
PARAMETER)

MAX. DROPLET DIAMETER = 95 MICRON

Figure 95. Mean droplet trajectories in 50-in horizontal duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 96. Random droplet trajectories in 50-in horizontal duct. for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

and differences indicated by them are expected to be valid. A limited number of random trajectories cannot be expected to show subtle differences. The more severe wetting indicated for right wall than the left with the 95 μm droplets can be traced to the fact that the atomizer velocity is in the same direction as the gas velocity along the right wall whereas they are oppositely directed along the left wall. On the right wall the momentum transfer between droplets and gas is likely to increase the gas velocity whereas it is likely to decrease the gas velocity on the left side. The increased velocity on the right side is likely to result in higher turbulence than on the left side of the atomizer. The higher gas velocity and accompanying higher turbulence intensity is probably responsible for the preferential wall wetting on the right wall shown by the flow model for the 95 μm droplets. Greater severity of wall wetting on the right side than the left was also shown to have been indicated by the wall thermo-couple data. The flow model therefore appears to reproduce an experimentally observed wetting asymmetry, despite its simplicity. The kinetic energy of turbulence shown in Figure 97 also shows the suspected right-to-left asymmetry in turbulence characteristics. The asymmetry in the trajectories is conspicuous for only the largest droplets (95 μm diameter). These large droplets comprise only a small fraction of the total number of droplets created in the atomizer, and as such do not influence to any large extent the right-to-left distribution of droplets in the duct. Figure 98 confirms this expectation showing the gas temperature, and hence the humidification extent are generally symmetric with respect to the duct center-line along the flow direction.

Case 2 - 70-in wide Horizontal Duct

The ability of the 2-dimensional flow simulation to reproduce the experimentally observed right-to-left wall wetting asymmetry in the case of the 50-in duct provide a basis for extending the 2-dimensional modeling to a larger duct in which wall wetting is totally absent. Simple droplet penetration calculations, together with reasonable allowance for turbulent spreading, indicated that 70-in to be close to the minimum duct width in which wall wetting will be totally absent. Figure 99 shows the finite difference grid used for this simulation. It is no different from that used in the preceding exercise except that the actual finite difference distances are larger. The mean trajectories for this case are shown in Figure 100, while a limited number of random trajectories are shown in Figure 101. The mean trajectories are in favor of well confined droplets within the duct with no trace of wall wetting. The random trajectories also indicate good confinement despite the spreading of the droplet trajectories by turbulence. There appears to be a tendency for trajectories to move close to the wall after about 25 ft of travel (about 0.5 sec) in the gas stream. However, since the droplets are essentially dry, at least to surface wetness, by this time, the wall deposition from these trajectories is likely to be dry, no different from flyash, and probably removable by the turbulence of the gas flow itself. The near-atomizer, right-to-left asymmetry in the kinetic energy of turbulence is shown in both Figure 102 and Figure 103. The droplets ejected toward the right wall appear to be subject to higher gas turbulence intensities. The gas temperature in this case shows a slight asymmetry probably because, as discussed earlier, the gas is travelling at a slightly higher

Figure 97. Profiles of the kinetic energy of turbulence in 50-in. horizontal duct.

Figure 98. Contours of the gas temperature in 50-in horizontal duct.

Figure 99. Finite difference grid for 70-in horizontal grid.

Figure 100. Mean droplet trajectories in 70-in horizontal duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 101. Random droplet trajectories in 70-in horizontal duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 102. Profiles of the kinetic energy of turbulence in 70-in. horizontal duct.

Figure 103. Contours of the kinetic energy of turbulence in 70-in. horizontal duct.

speed on the right side than the left (see Figures 105 and 106). The droplet mass concentration shown in Figure 104 is essentially symmetric about the axis of the duct along the flow direction indicating the symmetry of humidification. On the basis of the above analyses, the 70-in duct width appears to be satisfactory for preventing wall wetting from a slurry flow rate sufficient for achieving a 40 F approach to saturation.

Case 3 - Modified Horizontal Duct

Figure 107 shows a suggested modification to the Beverly plant for continuing atomizer-related studies without wall wetting. The modification requires replacing 20 ft of the 50-in wide duct with duct having a 70-in width. The remaining duct remains unchanged. The modification reduces the inlet gas velocity to the section. However, the argument is to obtain experimental data characteristic of non-wetting operation at this lower inlet velocity, and use flow modeling techniques to scale-up the results to the higher, design gas velocity. Figure 108 shows the finite difference grid, while Figures 109 and 110 show the transverse and axial velocity profiles along the modified duct. The transverse velocity profiles the effect of momentum exchange between droplet and gas. As a result of the counter-clockwise swirl of droplets produced by the atomizer, the gas flowing on the right side of the duct tends to be imparted a transverse velocity component. However, this transverse velocity component appears to be dissipated after only 5 ft travel in the duct. However the effect of this momentum transfer on the turbulence kinetic energy appears to persist over a much larger length of the duct, as shown in Figure 113. The right side of the duct (looking in the direction of flow) appears to show higher turbulent energy reflective of the higher transverse velocity transfer to this side of the duct. Figure 111 shows mean trajectories for droplets of various diameters, and Figure 112 show corresponding random trajectories. Both the mean and random trajectories indicate non-wetting droplet confinement. As in the case of the 70-in wide duct (Case 2), the random trajectories for the 95 μ m droplets appear to drift close to the duct walls after about 0.5 sec residence time. However, by this time they are dry and pose no wetting threat. Profiles of the droplet mass concentration are shown in Figure 114. The droplet mass appears to be confined to the core of the duct up to about 5 ft downstream of the atomizer. Beyond this point the droplet mass concentration seems to be distributed nearly uniformly across the duct except near the walls where the mass concentrations are nearly zero. Both profiles and contours of the gas temperature are shown in Figures 115 and 116. Figure 116 again displays the result of the droplet core observed in Figure 114. The expansion of the core with increasing downstream distance from the atomizer is also evident from the gas temperature contours.

Case 4 - Modified Vertical Duct

A schematic of the recommended vertical duct modification is shown in Figure 117. The finite difference grid used to model the modified vertical duct is shown in Figure 118. The modified duct comprises a 20 ft section of 70 in. diameter duct followed by 40 ft of the 50-in diameter

Figure 104. Profiles of the droplet mass concentration in 70-in. horizontal duct.

Figure 105. Profiles of the gas temperature in 70-in. horizontal duct.

Figure 106. Contours of the gas temperature in 70-in. horizontal duct.

Figure 107. Suggested horizontal duct (Station 2) modification.

Figure 108. Finite difference grid for modified horizontal grid.

Figure 109. Profiles of the transverse velocity in modified horizontal duct.

Figure 110. Profiles of the axial velocity in modified horizontal duct.

Figure 111. Mean droplet trajectories in modified horizontal duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 112. Random droplet trajectories in modified horizontal duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 113. Profiles of the kinetic energy of trubulence in modified horizontal duct.

Figure 114. Contours of the droplet mass concentration in modified horizontal duct.

Figure 115. Profiles of the gas temperature in modified horizontal duct.

Figure 116. Contours of the gas temperature in modified horizontal duct.

Figure 117. Suggested vertical duct (Station 1) modification.

Figure 118. Finite difference grid for modified vertical grid.

duct. The replacement of a 20-ft section of the existing 50-in diameter Station 1 duct with larger, 70-in diameter, duct is expected to be sufficient, as in Station 2, to completely eliminate wall wetting in the immediate vicinity of the atomizer. The FLUENT modeling of the modified Station 1 was performed in order to assess its wetting potential. Figures 119 and 120 show profiles of axial and transverse velocity components. The axial velocity in the neighborhood reflects the effects of the boundary condition at the atomizer wheel spinning counter-clockwise at a tip speed of 540 ft/s. Figures 121 and 122 show projections of the mean and random trajectories on a vertical plane as predicted by the analytical model for the modified vertical duct. These trajectories show non-wetting confinement of droplets similar to that seen earlier in the modified horizontal duct. Figure 123 and 124 show projections of the predicted mean and turbulence-induced random trajectories on a horizontal plane. In these figures, the duct projects as its circular cross-section. The projection of helical droplet trajectories show only the radial and angular components of the trajectories; these projections give no information on the axial movements of the droplets. The plus sign at the end of a droplet trajectory indicates complete evaporation of the droplet. Figure 125 shows a horizontal projection of random trajectories for only the 95 μ m droplets. The horizontal projections also confirm droplet confinement and consequent absence of wall wetting in the modified vertical duct. Figure 126 shows that the turbulence generation due to droplets from the atomizer is confined to only about a 5 ft duct length following the atomizer. In contrast, the turbulence effects due to droplet/gas mixing persisted up to about 20 ft downstream of the atomizer in the modified horizontal duct. Figures 127 and 128, for both profiles and contours of the gas temperature show the warmer gas temperatures toward the duct walls expected from droplet confinement away from the duct walls. The core of the duct is shown to be cooler. This is not unexpected since most of the droplets are confined to the duct core, as seen from the droplet trajectories of Figures 121 and 124.

There are significant differences in the momentum transfer occurring in the vertical and horizontal atomizer configurations. In the vertical duct, the gas velocity is at right angles to the direction of initial droplet projection by the atomizer, for all droplets. As a result, the angular momentum conservation requires the gas to be imparted a swirl in the direction of the atomizer rotation. As discussed for the previous cases, the liquid to gas momentum transfer in the horizontal duct results in a modified axial velocity flow field together with the development of a minor transverse flow field. Despite the above differences in the effect of the droplet/gas mixing in the two atomizer configurations, the droplet trajectories are not too different from those seen for the horizontal configuration. This is because the droplet penetration depends primarily on the initial droplet velocity being much larger than the gas velocity. Thus perturbations of the gas velocity will not seriously influence the droplet penetration. However, details of the gas flow field and its fluctuating component does affect the dispersion of the droplets once they have slowed down to zero relative velocity between the droplet and gas. The random trajectories shown in Figure 112 are also in favor of good droplet confinement within the 70-in diameter duct, with no evidence of wall wetting. Some random trajectories do appear to drift toward the walls as in the case of the horizontal duct, but these droplets are dry by

Figure 119. Profiles of the transverse velocity in modified vertical duct.

Figure 120. Profiles of the axial velocity in modified vertical duct.

Figure 121. X-Y projection of mean droplet trajectories in modified vertical duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 122. X-Y projection of random droplet trajectories in modified vertical duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 123. Y-Z projection of mean droplet trajectories in modified vertical duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 124. Y-Z projection of random droplet trajectories in modified vertical duct for 5, 15, 25, 35, 45, 55, 65, 77, and 95 μm droplets.

Figure 125. Y-Z projection of random droplet trajectories in modified vertical duct for 95 um droplets.

Figure 126. Profiles of the kinetic energy of trubulence in modified vertical duct.

Figure 127. Contours of the droplet mass concentration in modified vertical duct.

Figure 128. Contours of the gas temperature in modified vertical duct.

the time they approach the duct walls, and should pose no wetting threat. Figures 119 and 120 show the transverse and axial velocity profiles. The obstacle presented by the atomizer leads to an increase in the axial gas velocity away from the atomizer. The transverse velocity component in the case of the vertical duct is seen to be appreciable and extends several feet downstream of the atomizer. The swirl induced by the droplets ejected from the atomizer through droplet/gas momentum exchange is responsible for the transverse velocity. Far away from the atomizer it is nearly zero, until the transition to the smaller duct once again introduces transverse velocity components due to the turning gas. Figure 118 shows the kinetic energy of turbulence extending a greater distance than seen for the horizontal atomizer position. The contours of gas and droplet mass are in close conformity, since temperature lowering through adiabatic humidification is proportional to the droplet mass concentration.

While the 2-dimensional representation of Station 2 used above was sensitive to right-to-left asymmetries, it was, by assumption, incapable of showing top-to-bottom asymmetries. In the same way, the 2-dimensional representation of Station 1 with angular momentum will be sensitive to top-to-bottom asymmetries, but insensitive to angular differences (north-to-south asymmetries).

The expanded inlet section reduces the inlet design velocity from 60 ft/s to nearly half that value. However, the importance of demonstrating continuous non-wetting operation is of a higher priority. It is felt that once non-wetting operation is demonstrated, parametric results obtained with the lower inlet velocity can be scaled up to represent the design inlet velocity through detailed, 3-dimensional flow modeling.

6.0 CONCEPTUAL DESIGN OF 500 MW IDS IMPLEMENTATION

Figure 129 shows a general arrangement of the ductwork equipped with the proposed atomizers and airfoil mixing devices. Flue gas is assumed to exit the air-preheater in two 16 ft wide X 17 ft 4 in. high rectangular ducts with an average gas velocity of 60 ft/s. Each of these ducts is to be equipped with two, symmetrically mounted atomizer-airfoil combinations, as shown in Figure 130. A 30-ft duct section containing the atomizer and airfoil mounting hardware will be fabricated and retrofitted into the main ductwork between the air preheater outlet, and ESP inlet. The dual vortices associated with the airfoils are expected to promote uniform dispersion of the lime slurry injected into the gas stream by the atomizers.

Worksheets, prepared according to DOE's Economic Methodology, follow. A process description summary, as required in Worksheet 1, is not included, since the previous Sections of this report provide ample descriptions of the IDS process. The PFD of Figure 131 is included in place of Worksheet 2. All other Worksheets have been duly prepared.

The processing of the Worksheets are based on the following assumptions:

- (a) The plant to be retrofitted with the IDS system is already equipped with railspur and associated receiving equipment for unloading the lime reagent
- (b) The lime storage silos and lime slaker system are part of IDS costs reflected in the worksheets
- (c) An ESP already exists at this plant, and that any ESP upgrades before implementation of IDS is at the expense of the plant
- (d) Equipment costs relating to the lime system and the ash recycle system are based on recent cost estimates from GEESI suppliers. Differences between the current and previous equipment costs are due to differences in suppliers and time variation of costs
- (e) Retrofit factors are based on easy site access.

Worksheets 10 and 11 are newly designed for the purpose of summarizing the economic analyses outlined in the previous Worksheets. Worksheet 10 summarizes the fixed and variable operational costs, expressed as both first year and 30-year levelized figures. Worksheet 11 shows the capital cost as a distributed 30-year levelized figure, for comparison with the fixed operational cost figure. The capital and operational costs are also expressed as cost per ton of SO_2 removed in the Worksheets.

Figure 129. Proposed general arrangement for implementing IDS in the 500 MW reference plant.

Figure 130. Proposed atomizer and airfoil positioning for implementing IDS in 500 MW reference plant.

Figure 131. Process Flow Diagram (PFD) for 500 MW IDS implementation.

Figure 131. Process Flow Diagram (PFD) for 500 MW IDS implementation.

Figure 132(a). Piping & Instrumentation Diagram (PID) for atomizers in 500 MW IDS implementation.

Figure 132(b). PID for lime slurry preparation system in 500 MW IDS implementation.

Figure 132(c). PID for dry recycle system for 500 MW IDS implementation.

The capital retrofit cost of \$21.15 per kW of generating capacity (including capital requirement for NO_x removal at the 50% level) appears attractive in comparison with the cost figures for a conventional DFGD system. This capital cost figure reflects easy site access, and could be about 30% higher if site access conditions were difficult. Even under difficult site access conditions, the capital costs associated with IDS implementation on a 500 MW-scale appear to be favorable for serious retrofit consideration.

While the capital cost for IDS appears much smaller than for conventional DFGD system, the variable operating cost appears to be significantly larger than in the DFGD system. The principal factor responsible for the excess is the 50% lime utilization in IDS, compared with significantly higher lime utilizations in DFGD systems. However, the IDS lime utilization appears to be the highest among the in-duct processes currently demonstrated as acid rain precursor technologies. As a result the IDS process is commercially attractive in both capital and operational costs when compared with other in-duct technologies.

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 3 - CONCEPTUAL PROCESS DESIGN

RAW MATERIAL AND UTILITY SUMMARY

Item		Quantity/Unit Specified		
I.	Raw Materials and Utilities	Lot		
	Reagent, t/hr			
	A. Lime	17.3		
	Raw Water, gpm	368.6		
	Cooling Tower Blowdown Water, gpm	0.0		
	Other Energy (e.g., Fuel Oil, gpm)	0.0		
	Steam at High Pressure (> 100 psig), lb/hr	0.0		
	Steam at Low Pressure (< 100 psig), lb/hr	0.0		
	Power (Operating HP and kW)			
		Area	HP	kW
		10	279.0	231.2
		20	1084.1	860.0
		30	0.0	0.0
		40	1200.0	994.3
		50	0.0	0.0
		60	0.0	0.0
		70	-	3.0
		TOTAL	-	2088.4

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 3 - CONCEPTUAL PROCESS DESIGN (Continued...)

RAW MATERIAL AND UTILITY SUMMARY

Item	Quantity/Unit Specified
II. Process Effluents and By-Products	
SO ₂ , t/hr **	9.39
NO _x , t/hr ***	1.89
Flyash, t/hr	25.56
Sulfur Product, t/hr	36.35
Sulfur By-Product, t/hr	0.00
Waste Water, gpm	0.00

** Quantities specified are for the control
of DOE's 500 MWe Unit #1 base-case utility
boiler

*** Emitted from the herein proposed controlled
flue gas stream.

6E ENVIRONMENTAL SYSTEMS

WORKSHEET 4 - MAJOR PROCESS AREA CAPITAL ESTIMATE

PROCESS AREA: 10 (REAGENT FEED SYSTEM)

Major Process Equipment	No.	Factory Material	Field Material	Field Labor	Erected Cost	Sales Tax	Sub- Total	Retrofit Factor	Process Cost
1. Lime Prep. System	1	742,500	37,125	157,505	937,130	38,981	976,112	1.07	1,042,596
2. Air Piping	Lot	1,305	65	3,374	4,744	69	4,813	1.07	5,141
3. Process Water Piping	Lot	17,689	884	44,332	62,905	929	63,834	1.07	68,182
4. Lime Slurry Piping	Lot	14,119	706	45,512	60,337	741	61,079	1.07	65,239
Process Cost									1,181,157
Process Contingency (25%)									295,289
Total Process Cost (1982 \$)									1,476,446

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 4 - MAJOR PROCESS AREA CAPITAL ESTIMATE

PROCESS AREA: 20 (SO2 REMOVAL SYSTEM)

Major Process Equipment	No.	Factory Material	Field Material	Field Labor	Erected Cost	Sales Tax	Sub- Total	Retrofit Factor	Process Cost
1. Weather Enclosure	1	65,650	3,282	23,273	92,205	3,447	95,652	1.07	102,167
2. Atomizer Assemblies	5 *	1,324,656	66,233	32,647	1,423,535	69,544	1,493,080	1.07	1,594,776
Process Cost									1,696,942
Process Contingency (25%)									424,236
Total Process Cost (1982 \$)									2,121,178

* 4 Operational atomizer assemblies including lube systems, and variable frequency drives. 1 spare atomizer assembly with motor & instrumentation, but without lube system and variable frequency drive.

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 4 - MAJOR PROCESS AREA CAPITAL ESTIMATE

PROCESS AREA: 30 (FLUE GAS SYSTEM)

Major Process Equipment	No.	Factory Material	Field Material	Field Labor	Erected Cost	Sales Tax	Sub- Total	Retrofit Factor	Process Cost
1. Ductwork	Lot	67,165	3,358	25,357	95,880	3,526	99,406	1.07	106,177
2. S.L.W.R.	Lot	9,852	493	2,129	12,473	517	12,991	1.07	13,875
3. Support Steel	Lot	17,344	867	4,322	22,533	911	23,443	1.07	25,040
Process Cost									145,093
Process Contingency (25%)									36,273
Total Process Cost (1982 \$)									181,366

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 4 - MAJOR PROCESS AREA CAPITAL ESTIMATE

PROCESS AREA: 40 (REGENERATION SYSTEM)

Major Process Equipment	No.	Factory Material	Field Material	Field Labor	Erected Cost	Sales Tax	Sub- Total	Retrofit Factor	Process Cost
1. Dry Recycle System	1	316,935	15,847	40,513	373,294	16,639	389,933	1.07	416,492
2. Ash Delivery Piping	Lot	13,406	670	19,230	33,307	704	34,011	1.07	36,327
Process Cost									452,820
Process Contingency (25%)									113,205
Total Process Cost (1982 \$)									566,025

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 4 - MAJOR PROCESS AREA CAPITAL ESTIMATE

PROCESS AREA: 70 (GENERAL SUPPORT AREA)

Major Process Equipment	No.	Factory Material	Field Material	Field Labor	Erected Cost	Sales Tax	Sub- Total	Retrofit Factor	Process Cost
1. Instrum. & Controls	Lot	245,678	12,284	213,853	471,815	12,898	484,713	1.07	517,728
2. Site Supervision				113,443	113,443	0	113,443	1.07	121,170
3. Site Support Labor				74,131	74,131	0	74,131	1.07	79,180
4. Site Consumables				47,436	47,436	0	47,436	1.07	50,667
5. Site Rentals				94,873	94,873	0	94,873	1.07	101,335
Process Cost									870,080
Process Contingency (25%)									217,520
Total Process Cost (1982 \$)									1,087,600

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 5 - TOTAL PROCESS CAPITAL COST ESTIMATE SUMMARY

Area	Description	1982 \$/kW
10	Reagent Feed System	2.97
20	SO2 Removal System	4.26
30	Flue Gas System	0.36
40	Regenerative System	1.14
50	By-Product System	0.00
60	Waste Handling System	0.00
70	General Support Area	2.18
Process Capital Sub-Total		10.91

* \$/kW = (Total Process Area Cost)/(1500,000 kW - Process Power)

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 6 - EXISTING PLANT SCOPE ADJUSTMENT CAPITAL COST

ITEM	1982 \$/kW
(1) New Chimney (if a new chimney is needed, add \$7/kW)	0.00
(2) Coating Existing Chimney	0.00
- Fluoroelastomer, add \$3.61/kW	0.00
- FRP liner, add \$3.15/kW	0.00
- Borosilicate Glass Blocks, add \$3.61/kW	0.00
- Potassium Silicate Cement, add \$1.80/kW	0.00
- Flakeglass Reinforced, add \$1.35/kW	0.00
- Vinyl Ester, add \$1.35/kW	0.00
(3) Boiler Reinforcement (if absolutely needed, add \$4.50/kW)	0.00
(4) Draft Controls (instead of boiler reinforcement, if implosion controls will work, add \$1.30/kW)	0.00
(5) Demolition and relocation of existing equipment and buildings **	0.00
- Low number of existing interference to move, add \$0.30/kW	0.30
- Medium number of existing interference to move, add \$0.80/kW	0.00
- High number of existing interference to move, add \$1.50/kW	0.00
TOTAL	0.30

* Other scope adjustment capitals needed for byproduct system, cooli and particulate collector should be included in major process cost estimates

** Depending upon the location of major equipment, see Figure 1-3 for reference retrofit zones

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 7 - TOTAL CAPITAL REQUIREMENT RETROFIT ESTIMATE SUMMARY

ITEM	1982 \$/kW **
A. Total process area capital (from Worksheet 5)	10.91
B. Total plant scope adjustment capital (from Worksheet 6)	0.30
C. Total Process Capital, (A+B)	11.21
D. General Facilities, (10% of C)	1.12
E. Project Contingency, (22.5% of C)	2.52
F. Engineering and Home Office fees, (10% of C) †	1.12
G. Total plant retrofit cost, (C+D+E+F)	15.97
H. Allowance for funds during construction	0.00
1 Year, (0.0)	
2 Years, (18% of G)	
3 Years, (37% of G)	
I. Total plant retrofit investment, (H+I)	15.97
J. Royalty allowance, (.5% of C)	0.06
K. Preproduction Costs, (2% of I)	0.32
L. Inventory capital, (60 days of raw material & consumables from Worksheet 8)	
M. Initial catalyst & chemicals (from Worksheet 8)	
N. Total capital retrofit requirement, (I+J+K+L+M)	16.35

† Additional engineering and Home Office fee to account for underground obstruction factor are included in the overall retrofit factor calculation.

** \$/kW = Cost/(500,000 kW - Process Power)

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 8 - GENERALIZED FIRST YEAR OPERATING COST

PART I

Fixed Operating and Maintenance Costs		1982 \$/kW-Yr	1982 \$/hr
A.	Operating Labor *	0.076	18.30
B.	Maintenance Labor **	0.169	40.50
	Process Area Capital Cost ***	Maintenance Factor ****	
	- Process Area 10	2.97 X 0.075	21.33
	- Process Area 20	4.26 X 0.020	8.16
	- Process Area 30	0.36 X 0.030	1.03
	- Process Area 40	1.14 X 0.040	4.37
	- Process Area 50	0.00 -	0.00
	- Process Area 60	0.00 -	0.00
	- Process Area 70	2.18 X 0.020	4.17
	- Final Scope Adjustment *****		1.44
C.	Maintenance Material, 150% of (B)	0.254	60.75
D.	Administrative and Support Labor @ 30% of (A+B)	0.074	17.64
	Sub-Total, Part I - Fixed Cost (A+B+C+D)	0.573	137.19

* Operating labor cost, \$/kW-Yr =
 (# man wks/wk) (\$18.30/hr) (2080 hr/yr) / (500,000 kW-Process Power)

** Maintenance Labor =
 (0.4) (Process Capital Cost by Process Area) (Maintenance Factor)

*** Process Capital Cost for each Process Area is to be taken from
 Worksheet 5

**** Maintenance factor for each Process Area is to be taken from
 Table 9

***** Plant Scope Adjustment = (Total Plant Scope Adjustment Capital
 Cost from Worksheet 6) (Maintenance Factor of 0.2)

NOTE: For the purpose of bid simplification, a low maintenance
 factor is assumed for all capital cost adjustments made
 to the existing plant.

GE ENVIRONMENTAL SYSTEMS

WORKSHEET B - GENERALIZED FIRST YEAR OPERATING COST (Continued...)

=====

PART II

Operating and Maintenance Variable Operating Costs *****		1982 \$/kW-Yr	1982 \$/hr
=====			
A.	Reagents and Chemicals (see Table 2) Lime @ \$60.00/t	11.86	1037.28

B.	Cooling Water @ \$0.15/1000 gal	0.004	0.332

C.	High Pressure Steam @ \$3.75/1000 lb	0.00	0.00

D.	Low Pressure Steam @ \$3.02/1000 lb	0.00	0.00

E.	Power @ \$0.045/kWh	1.29	93.98

F.	Fuel Oil @ \$0.82/gal	0.00	0.00

G.	By-Product credit (see Table 5)	0.00	0.00

H.	Waste Disposal (see Table 5) Calcium Salts @ \$6.17/t	2.56	224.27

I.	Particulate Matter Control Costs (see Table 5)	0.00	0.00

Sub-Total Part II - Variable Operating Cost		15.72	1355.86
Total Generalized First Year Operating Costs (Sub-Total Part I and Sub-Total Part II)		16.29	
=====			

***** Variable Operating Costs, \$/kW-Yr =
 (\$ Cost/hr) (8670 hr/yr) (Capacity Factor) /
 (500,000 kW - Process Power)

Use a Capacity Factor of 0.78 for power cost, and a Capacity Factor
 of 0.65 for all other variable operating costs.

GE ENVIRONMENTAL SYSTEMS

WORKSHEET 10 - LEVELIZED OPERATING COSTS

ITEM	Levelized	Levelized
	\$/kW-Yr	\$/t SO2 Removed
A. Levelized Fixed Operating and Maintenance Cost	0.57	33.77
B. Levelized Variable Operating and Maintenance Cost	16.86	357.93

* \$/t SO2 Removed = (\$/hr, from Worksheet 8) (Level Factor) / (SO2 Removed, t/hr)

SO2 Removed = 9.385 t/hr (High Sulfur Coal)

30-Yr Level Factor Referred to 1982 = 2.31

WORKSHEET 11 - LEVELIZED CAPITAL COSTS

ITEM	1982 \$/kW	Levelized	Levelized
		\$/kW-Yr	\$/t SO2 Removed
A. Levelized Capital Cost	\$21.15	1.63	14.42

** Levelized \$/kW-Yr = (1982 \$/kW) (Level Factor) / (30 Yr)

*** Levelized \$/t SO2 Removed = [(Levelized \$/kW-Yr)
(500,000 kW-Process kW)]
/[(8760 hr/yr) (SO2 Removed, t/hr)
(Capacity Factor)]

SO2 Removed = 9.385 t/hr (High Sulfur Coal)

30-Yr Level Factor Referred to 1982 = 2.31

REFERENCES

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3. Apple, C. and M.E.Kelly. "Mechansims of Dry SO₂ Control Processes." EPA-600/7-82-026 (NTIS No. PB 82196924), April 1982.
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6. Snaddon, R.W.L. and N.A.Johnson. "Rotary Atomization of Lime Slurries for Dry Gas Desulfurization." Presented at ASME/IEE Power Generation Conference, Milwaukee, WI. October, 1985.
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8. Abauf, N. and F.W.Staub. "Drying of Liquid-Solid Slurry Droplets." GE-TIS Report No. 85CRD225, Schenectady, NY. December, 1985.

APPENDIX A - DOE/GE IDS PILOT PLANT STATION 1 (VERTICAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	1	2	3	4	5	6	7	8	9	10	11	12	13
DATE:	6/29/87	6/29/87	6/29/87	6/29/87	7/1/87	7/2/87	7/2/87	7/7/87	7/16/87	7/17/87	7/21/87	7/21/87	7/22/87
TEST DURATION, min:	28	29	31	30	48	48	47	53	54	55	51	54	55
INLET GAS FLOW RATE, acfm:	27,115	28,149	28,983	29,337	27,070	26,883	27,150	55,330	53,520	26,589	24,947	25,519	49,131
OUTLET GAS FLOW RATE, acfm:	25,782	25,686	25,551	25,587	24,900	25,010	24,977	50,430	47,397	23,544	22,248	22,270	43,798
INLET GAS TEMPERATURE, F:	329	330	333	333	328	334	332	337	337	331	331	333	342
GAS TEMPERATURE @ 1s, F:	266	223	198	189	232	259	243	245	223	198	209	196	224
OUTLET GAS TEMPERATURE, F:													
DILUTION WATER FLOW, gpm:	.00	.00	.00	.00	.00	2.40	2.66	5.66	5.67	.00	.57	.55	5.66
LIME SLURRY FLOW, gpm:	3.49	6.70	7.77	8.30	5.33	2.59	3.47	5.73	6.32	7.51	5.80	5.88	8.66
LIME SLURRY % SOLIDS (by mass):	18.5	18.5	18.5	18.5	18.5	18.5	18.5	19.3	16.5	19.8	19.0	19.0	23.8
LIME SLURRY SPECIFIC GRAVITY:	1.102	1.102	1.102	1.102	1.102	1.102	1.102	1.107	1.09	1.11	1.105	1.105	1.135
DRY SR, FRESH LIME:	0.51	0.99	1.14	1.23	0.89	0.43	0.57	0.46	0.45	1.33	1.05	1.09	1.04
SO ₂ CONCENTRATIONS:													
INLET, ppmvw(wet)	3,334	3,199	3,122	3,052	2,915	3,019	2,961	3,128	3,125	3,043	3,029	2,909	3,029
INLET, ppmvw(dry)	3,512	3,508	3,505	3,359	3,314	3,389	3,339	3,562	3,453	3,353	3,213	3,235	3,313
@ 1s, ppmvw(wet)	2,671	2,294	2,117	1,917	2,411	2,401	2,263	2,528	2,336	1,712	1,972	2,004	2,090
@ 1s, ppmvw(dry)	3,035	2,607	2,406	2,178	2,831	2,742	2,563	2,817		1,882	2,166	2,123	
@ ESP INLET, ppmvw(wet)	2,673	2,127	1,963	1,814	2,175	2,424	2,237	2,610		1,683	1,964	1,971	
@ ESP INLET, ppmvw(dry)	3,037	2,417	2,231	2,061	2,554	2,768	2,533	2,908		1,850	2,157	2,089	
OUTLET, ppmvw(wet)	2,591	2,070	1,808	1,616	2,097	2,259	2,168	2,370		1,545	1,739	1,778	
OUTLET, ppmvw(dry)	2,944	2,352	2,055	1,836	2,462	2,580	2,455	2,641		1,698	1,910	1,884	
SO ₂ REMOVAL EFFICIENCIES:													
1s (EVAPORATION ZONE)	13.6	25.7	31.3	35.2	14.6	19.1	23.3	20.9		43.9	32.6	34.4	
DRIFT ZONE (% OF INLET)	.0	7.3	7.3	5.4	9.8	.0	1.1	.0		1.7	.4	1.6	
ESP (% OF INLET)	3.1	2.7	7.9	10.9	3.6	6.8	3.1	9.2		8.2	11.5	9.8	
SYSTEM	16.2	33.0	41.4	45.3	25.7	23.9	26.5	25.9		49.4	40.6	41.8	
LIME UTILIZATION, % :	31.7	33.3	36.3	36.9	28.9	55.5	46.4	56.2		37.1	38.6	38.3	

APPENDIX A (CONT'D...) DOE/GE IDS PILOT PLANT STATION 1 SO₂ REMOVAL DATA SUMMARY

TEST NO:	14	15	16	17	18	19	20	21	22	23	24	25
DATE:	7/23/87	7/23/87	7/23/87	7/24/87	7/24/87	7/27/87	7/27/87	7/28/87	7/28/87	7/29/87	7/29/87	7/31/87
TEST DURATION, min:	54	55	55	55	55	56	56	51	56	45	46	45
INLET GAS FLOW RATE, acfm:	25,708	25,815	25,674	48,497	48,934	48,982	49,121	47,025	47,615	47,990	47,690	47,084
OUTLET GAS FLOW RATE, acfm:	22,491	22,473	22,507	41,477	41,431	42,850	42,563	41,119	41,181	41,634	41,619	41,932
INLET GAS TEMPERATURE, F:	338	338	337	340	340	336	330	339	338	340	335	341
GAS TEMPERATURE @ 1s, F:	200	194	200	202	193	205	193	194	203	209	209	214
OUTLET GAS TEMPERATURE, F:												
DILUTION WATER FLOW, gpm:	.22	.32	.00	5.65	5.66	2.05	3.49	.00	2.72	3.20	3.60	.00
LIME SLURRY FLOW, gpm:	6.75	7.16	6.79	5.98	6.70	9.68	9.62	14.24	7.88	7.33	7.24	12.37
LIME SLURRY % SOLIDS (by mass):	23.8	23.8	23.8	22.2	22.2	22.2	22.2	22.2	22.2	23.8	23.8	23.8
LIME SLURRY SPECIFIC GRAVITY:	1.135	1.135	1.135	1.125	1.125	1.125	1.125	1.125	1.125	1.135	1.135	1.135
DRY SR, FRESH LIME:	1.47	1.53	1.45	0.62	0.69	1.06	1.12	1.50	0.88	0.87	0.85	1.39
SO ₂ CONCENTRATIONS:												
INLET, ppmvw(wet)	3,158	3,203	3,230	3,284	3,272	3,040	2,842	3,315	3,093	3,112	3,159	3,365
INLET, ppmvw(dry)	3,452	3,439	3,448	3,585	3,587	3,235	3,050	3,617	3,344	3,315	3,338	3,750
@ 1s, ppmvw(wet)	1,978	1,927	2,110	2,577	2,381	2,387	1,883	2,000	2,340	2,408	2,346	2,130
@ 1s, ppmvw(dry)	1,962	1,930	2,291	2,566	2,466	2,527	2,139	2,358	2,667	2,737	2,577	2,322
@ ESP INLET, ppmvw(wet)	1,522	1,794	2,018	2,441	2,331	2,003	1,853	1,902	2,349	2,318	2,375	2,109
@ ESP INLET, ppmvw(dry)	1,509	1,796	2,191	2,431	2,414	2,120	2,105	2,242	2,677	2,634	2,609	2,299
OUTLET, ppmvw(wet)	1,693	1,490	1,608	2,430	2,072	1,745	1,565	1,510	2,055	2,279	2,180	1,944
OUTLET, ppmvw(dry)	1,679	1,492	1,746	2,420	2,146	1,847	1,778	1,780	2,342	2,590	2,395	2,119
SO ₂ REMOVAL EFFICIENCIES:												
1s (EVAPORATION ZONE)	43.2	43.9	33.6	28.4	31.3	21.9	29.9	34.8	20.3	17.4	22.8	38.1
DRIFT ZONE (% OF INLET)	23.1	6.9	4.4	5.3	2.1	16.1	1.6	4.9	.0	3.7	.0	1.0
ESP (% OF INLET)	.0	16.9	20.3	.5	11.1	12.9	15.5	20.6	12.5	1.7	8.2	7.8
SYSTEM	51.4	56.6	49.4	32.5	40.2	42.9	41.7	50.8	30.0	21.9	28.3	43.5
LIME UTILIZATION, % :	34.9	37.0	34.0	52.4	58.2	40.5	37.2	33.9	34.1	25.1	33.2	31.3

APPENDIX B
DOE/GE IDS PILOT PLANT STATION 2 (HORIZONTAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	1	2	3	4	5	6
DATE:	10/5/87	10/5/87	10/5/87	10/7/87	10/7/87	10/7/87
BOILER LOAD, MW:	540	539	542	544	541	538
INLET GAS FLOW RATE, acfm:	24,764	23,207	24,840	49,285	49,828	50,492
OUTLET GAS FLOW RATE, acfm:	22,307	21,207	22,488	47,348	47,380	47,273
INLET GAS TEMPERATURE, F:	325	325	323	336	335	336
GAS TEMPERATURE @ 1s, F:	218	223	191	303	288	257
OUTLET GAS TEMPERATURE, F:	224	231	214	298	284	265
DILUTION WATER FLOW, gpm:	0	0	0	0	0	0
LIME SLURRY FLOW, gpm:	3.48	3.68	5.36	1.82	3.34	5.88
LIME SLURRY % SOLIDS (by mass):	17.0	17.0	17.0	19.8	19.8	19.8
LIME SLURRY SPECIFIC GRAVITY:	1.09	1.09	1.09	1.11	1.11	1.11
ATOMIZER SPEED, rpm:	14,123	14,118	14,106	14,136	14,114	14,075
NO. OF ATOMIZER NOZZLES:	8	8	8	8	8	8
OFF-PRODUCT AGE, hr:	0	0	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0	0
DRY SR, FRESH LIME:	0.44	0.49	0.67	0.16	0.29	0.50
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	0.44	0.49	0.67	0.16	0.29	0.46
SO ₂ CONCENTRATIONS:						
INLET, ppmvw(wet)	3,539	3,568	3,540	2,999	3,056	3,088
INLET, ppmvw(dry)	3,835	3,802	3,869	3,380	3,475	3,454
@ 1s, ppmvw(wet)	2,855	2,967	2,967	3,264	3,084	2,866
@ 1s, ppmvw(dry)	2,873	3,461	2,852	3,268	3,435	3,247
@ ESP INLET, ppmvw(wet)	2,855	2,967	2,967	3,264	3,084	2,747
@ ESP INLET, ppmvw(dry)	2,873	3,461	2,852	3,268	3,435	3,113
OUTLET, ppmvw(wet)	2,789	2,635	2,868	3,184	2,810	2,570
OUTLET, ppmvw(dry)	2,807	3,074	2,757	3,188	3,130	2,912
SO ₂ REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	25.1	9.0	26.3	3.3	1.2	6.0
DRIFT ZONE (% OF INLET)	.0	.0	.0	.0	.0	4.1
ESP (% OF INLET)	2.3	11.2	3.3	2.5	8.9	6.4
SYSTEM	26.8	19.2	28.7	5.7	9.9	15.7
ELECTROSTATIC PRECIPITATOR DATA :						
1R SET A, kV	0	0	0	33.6	33.4	33.4
1R SET A, mA	0	0	0	310	309	309
1R SET B, kV	0	0	0	35.2	34.9	35.1
1R SET B, mA	0	0	0	307	307	307
1R SET C, kV	0	0	0	32.4	32.5	33
1R SET C, mA	0	0	0	225	225	225
1R SET D, kV	0	0	0	41.6	34.5	38.2
1R SET D, mA	0	0	0	224	222	164
ESP POWER, kW	.00	.00	.00	37.83	36.01	34.79
OUTLET OPACITY, %				14.7	15.7	1.6
WING CONFIGURATION:						
HOSE POSITION, in.	31	31	31	31	31	31
ANGLE, deg.	15	15	15	20	20	20
WIDTH, in.	12	12	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :						
DEPTH, in.	9	9	9	9	9	9
DISTANCE OFF DUCT CENTER, in.	2	2	2	2	2	2

APPENDIX B (CONT'D...)
DOE/GE IDS PILOT STATION 2 (HORIZONTAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	7	8	9	10	11	12
DATE:	10/8/87	10/8/87	10/8/87	10/8/87	11/9/87	11/9/87
BOILER LOAD, MW:	544	549	547	548	600	609
INLET GAS FLOW RATE, acfm:	53,884	52,804	50,950	48,353	26,649	26,283
OUTLET GAS FLOW RATE, acfm:	50,038	48,854	46,264	43,098	24,777	24,437
INLET GAS TEMPERATURE, F:	339	334	335	335	336	335
GAS TEMPERATURE @ 1s, F:	239	225	196	169	187	182
OUTLET GAS TEMPERATURE, F:	258	248	224	203	243	237
DILUTION WATER FLOW, gpm:	0	0	0	0	2.68	.7
LIME SLURRY FLOW, gpm:	7.62	8.46	11.8	14.16	2.89	5.93
LIME SLURRY % SOLIDS (by mass):	21.5	21.5	21.5	21.5	21.0	21.0
LIME SLURRY SPECIFIC GRAVITY:	1.112	1.112	1.132	1.112	1.112	1.112
ATOMIZER SPEED, rpm:	14,058	14,035	13,974	13,925	14,083	14,064
NO. OF ATOMIZER NOZZLES:	8	8	8	8	8	8
OFF-PRODUCT AGE, hr:	0	0	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0	0
DRY SR, FRESH LIME:	0.65	0.74	1.11	1.33	0.48	0.89
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	0.65	0.74	1.11	1.33	0.48	0.46
SO ₂ CONCENTRATIONS:						
INLET, ppmvw(wet)	3,149	3,118	3,065	3,188	3,199	3,601
INLET, ppmvw(dry)	3,460	3,403	3,368	3,692	3,558	3,807
@ 1s, ppmvw(wet)	2,498	2,391	1,997	1,908	2,475	2,256
@ 1s, ppmvw(dry)	2,758	2,676	2,259	2,135	2,796	2,657
@ ESP INLET, ppmvw(wet)	2,498	2,354	1,986	1,883	2,520	2,213
@ ESP INLET, ppmvw(dry)	2,758	2,635	2,246	2,107	2,847	2,606
OUTLET, ppmvw(wet)	2,468	2,257	1,968	1,751	2,485	2,044
OUTLET, ppmvw(dry)	2,725	2,526	2,226	1,959	2,807	2,407
SO ₂ REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	20.3	21.4	32.9	42.2	21.4	30.2
DRIFT ZONE (% OF INLET)	.0	1.5	.6	1.3	.0	1.9
ESP (% OF INLET)	1.2	4.1	.9	7.0	1.4	7.6
SYSTEM	21.2	25.8	33.9	46.9	21.1	36.8
ELECTROSTATIC PRECIPITATOR DATA :						
IR SET A, kV	33.8	33.7	34.6	36.4	34.5	34.3
IR SET A, mA	311	310	311	314	312	311.7
IR SET B, kV	36.3	37.4	36.8	38.8	36.3	36.1
IR SET B, mA	310	311	310	314	311.1	310.8
IR SET C, kV	33.6	35.8	35.5	37.4	33.2	33.1
IR SET C, mA	226	228	228	230	226.7	226.4
IR SET D, kV	44.3	51.5	56.9	57.6	46.1	45.9
IR SET D, mA	227	245	202	172.3	229.1	228.7
ESP POWER, kW	39.41	42.86	41.76	42.14	40.14	39.90
OUTLET OPACITY, %						
WING CONFIGURATION:						
NOSE POSITION, in.	29	29	29	29	27	27
ANGLE, deg.	18	18	18	18	19	19
WIDTH, in.	12	12	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :						
DEPTH, in.	9	9	9	9	13	13
DISTANCE OFF DUCT CENTER, in.	2	2	2	2	0	0

APPENDIX B (CONT'D...)
DOE/GE IDS PILOT PLANT STATION 2 (HORIZONTAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	13	14	15	16	17	18
DATE:	11/10/87	11/17/87	11/18/87	11/23/87	11/24/87	11/24/87
BOILER LOAD, MW:	611	579		618	608	594
INLET GAS FLOW RATE, acfm:	51,962	51,875	27,006	48,921	26,149	26,688
CUTLET GAS FLOW RATE, acfm:	47,201	47,143	25,275	43,648	24,025	23,772
INLET GAS TEMPERATURE, F:	358	345	332	367	346	344
GAS TEMPERATURE @ 1s, F:	190	190	185	174	207	168
CUTLET GAS TEMPERATURE, F:	240	229	240	225	242	210
DILUTION WATER FLOW, gpm:	0	0	0	1.48	0	.15
LIME SLURRY FLOW, gpm:	13.14	13.39	6.88	13.92	6.1	7.66
LIME SLURRY % SOLIDS (by mass):	21.0	21.0	23.8	23.8	23.8	23.8
LIME SLURRY SPECIFIC GRAVITY:	1.112	1.112	1.132	1.132	1.132	1.132
ATOMIZER SPEED, rpm:	13,983	13,977	14,068	13,905	14,070	14,031
NO. OF ATOMIZER NOZZLES:	8	8	8	8	8	8
CFF-PRODUCT AGE, hr:	0	0	0	0	0	0
CFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0	0
CFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0	0
DRY SR, FRESH LIME:	1.13	1.17	1.16	1.44	1.24	1.53
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	1.13	1.17	1.16	1.44	1.24	1.53
SO ₂ CONCENTRATIONS:						
INLET, ppmvw(wet)	3,260	3,153	3,577	3,352	3,102	3,091
INLET, ppmvw(dry)	3,603	3,512	3,692	3,694	3,471	3,390
@ 1s, ppmvw(wet)	2,165	2,273	2,296	1,886	1,973	1,545
@ 1s, ppmvw(dry)	2,489	2,597	2,536	2,083	2,345	1,792
@ ESP INLET, ppmvw(wet)	2,169	2,273	2,089	1,866	1,943	1,545
@ ESP INLET, ppmvw(dry)	2,494	2,597	2,308	2,061	2,309	1,792
CUTLET, ppmvw(wet)	1,944	1,917	1,986	1,743	1,824	1,467
CUTLET, ppmvw(dry)	2,235	2,190	2,194	1,926	2,168	1,702
SO ₂ REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	30.9	26.1	31.3	43.6	32.4	47.1
DRIFT ZONE (% OF INLET)	.0	.0	9.0	1.0	1.5	.0
ESP (% OF INLET)	10.4	15.7	4.9	6.6	6.1	5.0
SYSTEM	38.0	37.6	40.6	47.9	37.5	49.8
ELECTROSTATIC PRECIPITATOR DATA :						
TR SET A, kV	35.0	35.0	35.0	35.9	34.5	35.9
TR SET A, mA	319.4	318.8	318.8	318.0	315.0	317.2
TR SET B, kV	37.3	36.9	36.2	37.3	35.1	37.0
TR SET B, mA	320.2	318.5	317.4	317.4	312.8	315.7
TR SET C, kV	35.9	35.7	33.2	36.5	32.2	34.1
TR SET C, mA	235.0	234.2	231.2	233.9	228.5	230.0
TR SET D, kV	55.4	56.1	45.2	57.2	42.4	47.8
TR SET D, mA	169.9	186.1	232.4	179.1	222.6	230.3
ESP POWER, kW	40.97	41.71	40.83	42.04	38.64	41.92
CUTLET OPACITY,%		2	.9	6	2.5	1.6
WING CONFIGURATION:						
NOSE POSITION, in.	27	27	27	27	27	27
ANGLE, deg.	19	23	23	23	23	23
WIDTH, in.	12	12	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :						
DEPTH, in.	13	13	13	13	13	13
DISTANCE OFF DUCT CENTER, in.	0	0	0	0	0	0

APPENDIX B (CONT'D...)
DOE/GE IDS PILOT PLANT STATION 2 (HORIZONTAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	19	20	21	22	23	24
DATE:	12/8/87	12/16/87	1/18/88	1/20/88	1/21/88	1/21/88
BOILER LOAD, MW:	568	586	618	588	619	604
INLET GAS FLOW RATE, acfm:	26,290	54,330	26,729	25,289	50,561	47,481
OUTLET GAS FLOW RATE, acfm:	24,387	49,734	25,038	24,819	47,701	44,931
INLET GAS TEMPERATURE, F:	338	361	332	341	355	347
GAS TEMPERATURE @ 1s, F:	190	189	170	189	169	170
OUTLET GAS TEMPERATURE, F:	240	250	237	269	254	249
DILUTION WATER FLOW, gpm:	0	0	3.74	1.48	5.19	.85
LIME SLURRY FLOW, gpm:	6.44	12.93	3.09	6.71	10.25	14.45
LIME SLURRY % SOLIDS (by mass):	22.0	20.0	23.2	23.2	23.2	23.2
LIME SLURRY SPECIFIC GRAVITY:	1.114	1.106	1.131	1.131	1.131	1.131
ATOMIZER SPEED, rpm:	14,045	13,934	14,052	14,069	13,939	13,935
NO. OF ATOMIZER NOZZLES:	8	4	2	2	2	2
OFF-PRODUCT AGE, hr:	0	0	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0	0
DRY SR, FRESH LIME:	1.15	1.01	0.57	1.27	0.97	1.46
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	1.15	1.01	0.57	1.27	0.97	1.46
SO ₂ CONCENTRATIONS:						
INLET, ppmvw(wet)	3,162	3,252	3,239	3,339	3,424	3,367
INLET, ppmvw(dry)	3,341	3,451	3,406	3,393	3,542	3,578
@ 1s, ppmvw(wet)	1,837	1,934	2,234	1,949	1,981	2,041
@ 1s, ppmvw(dry)	2,133	2,221	2,583	2,145	2,249	2,332
@ ESP INLET, ppmvw(wet)	1,837	1,880	2,165	1,949	1,949	2,041
@ ESP INLET, ppmvw(dry)	2,133	2,159	2,503	2,145	2,213	2,332
OUTLET, ppmvw(wet)	1,760	1,837	2,018	1,738	1,922	1,612
OUTLET, ppmvw(dry)	2,044	2,110	2,333	1,913	2,182	1,842
SO ₂ REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	36.2	35.6	24.2	36.8	36.5	34.8
DRIFT ZONE (% OF INLET)	.0	2.8	3.1	.0	1.6	.0
ESP (% OF INLET)	4.2	2.3	6.8	10.8	1.4	21.0
SYSTEM	38.8	38.9	31.5	43.6	38.4	48.5
ELECTROSTATIC PRECIPITATOR DATA :						
TR SET A, kV	34.8	34.7	34.8	33.7	34	34.3
TR SET A, mA	321.5	318.6	318.3	315.3	317.5	317.7
TR SET B, kV	36	36.6	36.1	34.2	35.6	35.8
TR SET B, mA	320.8	319.5	317.6	313.8	317.2	318.6
TR SET C, kV	32.2	37.1	34.2	32.1	34.3	33.9
TR SET C, mA	232.6	237.8	232.9	229.9	233.5	233.3
TR SET D, kV	42.9	43.6	36.9	41.8	54.4	55.4
TR SET D, mA	228.9	100.4	98.1	220.3	202.6	223.4
ESP POWER, kW	40.05	35.95	34.13	37.95	41.12	42.59
OUTLET OPACITY, %	2.7		1.3	4.1	5	3.9
WING CONFIGURATION:						
NOSE POSITION, in.	NO WING	NO WING	27	27	27	27
ANGLE, deg.	NO WING	NO WING	20	20	20	20
WIDTH, in.	NO WING	NO WING	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :						
DEPTH, in.	13	13	13	13	13	13
DISTANCE OFF DUCT CENTER, in.	0	0	0	0	0	0
TURGITOL, ppm	0	500	0	0	0	0

APPENDIX B (CONT'D...)
DOE/GE IDS PILOT PLANT STATION 2 (HORIZONTAL DUCT) SO₂ REMOVAL DATA SUMMARY

TEST NO:	25	26	27	28	29
DATE:	1/22/88	2/1/88	2/1/88	2/3/88	2/3/88
BOILER LOAD, MW:	593	623	623	615	600
INLET GAS FLOW RATE, acfm:	49,814	49,562	48,604	60,413	61,722
OUTLET GAS FLOW RATE, acfm:	44,386	45,183	43,697	55,411	55,757
INLET GAS TEMPERATURE, F:	362	344	344	364	357
GAS TEMPERATURE @ 1s, F:	170	189	192	188	191
OUTLET GAS TEMPERATURE, F:	230	229	228	252	241
DILUTION WATER FLOW, gpm:	5.6	0	4.43	.96	5.62
LIME SLURRY FLOW, gpm:	6.23	13.38	5.31	14.23	7.11
LIME SLURRY % SOLIDS (by mass):	23.2	23.2	23.2	23.2	23.2
LIME SLURRY SPECIFIC GRAVITY:	1.131	1.131	1.131	1.131	1.131
ATOMIZER SPEED, rpm:	13,996	13,967	14,022	13,935	13,962
NO. OF ATOMIZER NOZZLES:	2	2	2	2	2
OFF-PRODUCT AGE, hr:	0	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0
DRY SR, FRESH LIME:	0.62	1.38	0.57	1.18	0.58
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	0.62	1.38	0.57	1.18	0.58
SO ₂ CONCENTRATIONS:					
INLET, ppmvw(wet)	3,338	3,155	3,080	3,301	3,247
INLET, ppmvw(dry)	3,615	3,399	3,364	3,525	3,467
@ 1s, ppmvw(wet)	2,275	1,941	2,231	2,245	2,253
@ 1s, ppmvw(dry)	2,478	2,171	2,499	2,470	2,470
@ ESP INLET, ppmvw(wet)	2,275	1,852	2,139	2,020	2,174
@ ESP INLET, ppmvw(dry)	2,478	2,072	2,396	2,222	2,384
OUTLET, ppmvw(wet)	2,194	1,821	2,118	1,969	2,188
OUTLET, ppmvw(dry)	2,390	2,037	2,372	2,166	2,399
SO ₂ REMOVAL EFFICIENCIES:					
1s (EVAPORATION ZONE)	31.5	36.1	25.7	29.9	28.8
DRIFT ZONE (% OF INLET)	.0	4.6	4.1	10.0	3.5
ESP (% OF INLET)	3.6	1.7	1.0	2.5	.0
SYSTEM	33.9	40.1	29.5	38.6	30.8
ELECTROSTATIC PRECIPITATOR DATA :					
IR SET A, kV	36.4	35.2	35.1	34.8	34.8
IR SET A, mA	325.3	323.2	322.1	323.8	322.4
IR SET B, kV	38.1	36.6	36.3	36.9	36.7
IR SET B, mA	326.6	322.6	321.8	326.1	322.7
IR SET C, kV	37.7	34.1	34.2	35.9	35.5
IR SET C, mA	241.5	236	235.1	239.6	237.5
IR SET D, kV	44.5	54.6	54.3	54.5	55.3
IR SET D, mA	52.7	221.1	228	179.6	195.3
ESP POWER, kW	35.73	43.30	43.41	41.69	42.29
OUTLET OPACITY, %	2.2	2	1.9	2.7	2.4
WING CONFIGURATION:					
NOSE POSITION, in.	27	27	27	27	27
ANGLE, deg.	20	20	20	20	20
WIDTH, in.	12	12	12	12	12
FLAP CONFIGURATION:					
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :					
DEPTH, in.	13	13	13	13	13
DISTANCE OFF DUCT CENTER, in.	0	0	0	0	0

APPENDIX C
DOE/GE IDS PILOT PLANT DATA SUMMARY ON SO₂ REMOVAL BY STATION 2 WALLS

TEST NO:	1	2	3	4
DATE:	2/26/88	3/2/88	3/8/88	3/11/88
BOILER LOAD, MW:	603	576	533	576
INLET GAS FLOW RATE, acfm:	27,861	51,343	52,728	27,767
OUTLET GAS FLOW RATE, acfm:	25,758	49,627	50,319	25,022
INLET GAS TEMPERATURE, F:	348	348	350	339
GAS TEMPERATURE @ 1s, F:	316	335	344	318
OUTLET GAS TEMPERATURE, F:	287	321	313	260
DILUTION WATER FLOW, gpm:	0	0	0	0
LIME SLURRY FLOW, gpm:	0	0	0	0
LIME SLURRY % SOLIDS (by mass):	0	0	0	0
LIME SLURRY SPECIFIC GRAVITY:	0	0	0	0
ATOMIZER SPEED, rpm:	14,136	14,152	14,165	14,155
NO. OF ATOMIZER NOZZLES:	2	2	2	2
OFF-PRODUCT AGE, hr:	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0
DRY SR, FRESH LIME:	0	0	0	0
DRY SR, OFF-PRODUCT:	0	0	0	0
DRY SR, FRESH LIME+OFF-PRODUCT:	0	0	0	0
SO ₂ CONCENTRATIONS:				
INLET, ppmvw(wet)	3,172	3,260	3,287	3,391
INLET, ppmvw(dry)	3,420	3,520	3,510	3,641
@ 1s, ppmvw(wet)	3,039	3,209	3,262	3,235
@ 1s, ppmvw(dry)	3,132	3,340	3,391	3,385
@ ESP INLET, ppmvw(wet)	3,039	3,209	3,262	3,235
@ ESP INLET, ppmvw(dry)	3,132	3,340	3,391	3,385
OUTLET, ppmvw(wet)	3,054	3,307	3,266	3,205
OUTLET, ppmvw(dry)	3,147	3,442	3,395	3,354
SO ₂ REMOVAL EFFICIENCIES:				
1s (EVAPORATION ZONE)	8.4	5.1	3.4	7.0
DRIFT ZONE (% OF INLET)	.0	.0	.0	.0
ESP (% OF INLET)	.0	.0	.0	.9
SYSTEM	8.0	2.2	3.3	7.9
ELECTROSTATIC PRECIPITATOR DATA :				
TR SET A, kV	34.0	35.7	34.8	32.9
TR SET A, mA	324.0	325.0	321.0	319.0
TR SET B, kV	37.0	36.3	36.1	34.9
TR SET B, mA	229.0	304.0	324.8	321.0
TR SET C, kV	34.7	35.0	35.2	32.4
TR SET C, mA	239.0	239.0	237.0	234.0
TR SET D, kV	39.8	39.0	37.2	34.9
TR SET D, mA	226.0	94.0	130.0	219.0
ESP POWER, kW	36.78	34.67	36.07	36.92
OUTLET OPACITY, %	1.5	6.8	12.2	9.7
WING CONFIGURATION:				
NOSE POSITION, in.	29	29	29	29
ANGLE, deg.	18	18	18	18
WIDTH, in.	12	12	12	12
FLAP CONFIGURATION:				
LEFT FLAP POSITION:	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION:	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :				
DEPTH, in.	9	9	9	9
DISTANCE OFF DUCT CENTER, in.	0	0	0	0

APPENDIX D
DOE/GE IDS PILOT PLANT DRY INJECTION NO. REMOVAL DATA SUMMARIES

	P R E C U R S O R T E S T S					
TEST NO:	1	2	3	4	5	6
DATE:	2/17/88	2/22/88	2/25/88	3/1/88	3/7/88	3/10/88
BOILER LOAD, MW:	600	591	582	563	575	554
INLET GAS FLOW RATE, acfm:	28,747	28,404	29,451	56,227	56,524	56,956
OUTLET GAS FLOW RATE, acfm:	25,339	24,921	25,860	49,981	49,937	50,361
INLET GAS TEMPERATURE, F:	339	340	355	355	357	361
GAS TEMPERATURE @ 1s, F:	188	190	190	187	192	192
OUTLET GAS TEMPERATURE, F:	203	207	223	221	222	226
DILUTION WATER FLOW, gpm:	1.85	.73	.25	3.52	2.48	2.60
LIME SLURRY FLOW, gpm:	5.49	5.48	5.58	11.03	10.98	10.85
LIME SLURRY % SOLIDS (by mass):	23.0	23.0	23.0	24.0	24.0	24.0
LIME SLURRY SPECIFIC GRAVITY:	1.128	1.128	1.129	1.132	1.132	1.132
ATOMIZER SPEED, rpm:	14,000	14,000	14,000	14,000	14,000	14,000
NO. OF ATOMIZER NOZZLES:						
OFF-PRODUCT AGE, hr:	0	0	0	0	0	0
OFF-PRODUCT % Ca(OH) ₂ (by mass):	0	0	0	0	0	0
OFF-PROD INJECTION RATE, lb/min:	0	0	0	0	0	0
DRY SR, FRESH LIME:	0.99	01.00	01.01	01.03	01.06	0.94
DRY SR, OFF-PRODUCT:	0.00	0.00	0.00	0.00	0.00	0.00
DRY SR, FRESH LIME+OFF-PRODUCT:	0.99	01.00	01.01	01.03	01.06	0.94
SO ₂ CONCENTRATIONS:						
INLET, ppmvw(wet)	3,037	3,052	3,028	3,201	3,105	3,429
INLET, ppmvw(dry)	3,216	3,416	3,212	3,355	3,373	3,529
OUTLET, ppmvw(dry)	1,785	1,844	1,962	1,893	1,887	2,048
NO _x CONCENTRATIONS:						
INLET, ppmvw(wet)	587	633	592	595	625	541
INLET, ppmvw(dry)	632	651	644	634	647	583
OUTLET, ppmvw(dry)	580	597	588	615	614	563
SYSTEM SO ₂ REMOVAL EFFICIENCY:	44.5	46.0	38.9	43.6	44.1	42.0
SYSTEM NO _x REMOVAL EFFICIENCY:	8.2	8.3	8.7	3.0	5.1	3.4
ELECTROSTATIC PRECIPITATOR DATA :						
TR SET A, kV	30.0	34.1	35.7	31.7	32.1	30.8
TR SET A, mA	315.0	320.0	326.0	317.0	317.0	316.0
TR SET B, kV	32.6	35.4	37.2	32.9	35.0	34.2
TR SET B, mA	315.0	320.0	328.0	320.0	321.0	320.0
TR SET C, kV	31.4	32.8	34.7	37.5	35.4	34.4
TR SET C, mA	231.0	233.0	238.0	241.0	237.0	236.0
TR SET D, kV	48.4	45.4	48.3	44.9	57.5	56.6
TR SET D, mA	232.0	228.0	241.0	51.4	187.0	191.0
ESP POWER, kW	38.20	40.23	43.74	31.92	40.55	39.61
OUTLET OPACITY, %	2.8	4.6	1.4	4.3	6.1	7.2
WING CONFIGURATION:						
HOSE POSITION, in.	29	29	29	29	29	29
ANGLE, deg.	18	18	18	18	18	18
WIDTH, in.	12	12	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION :						
DEPTH, in.	9	9	9	9	9	9
DISTANCE OFF DUCT CENTER, in.	0	0	0	0	0	0

APPENDIX D (CONT'D...)
DOE/GE IDS PILOT PLANT DRY INJECTION NO. REMOVAL DATA SUMMARY

	TESTS WITH DRY INJECTION					
TEST NO:	1	2	3	4	5	6
DATE:	2/19/88	2/23/88	2/26/88	3/2/88	3/8/88	3/11/88
BOILER LOAD, MW:	621	603	604	572	560	577
INLET GAS FLOW RATE, acfm:	25,882	28,621	28,106	57,004	54,663	28,529
OUTLET GAS FLOW RATE, acfm:	23,712	25,752	25,049	50,280	48,747	25,325
INLET GAS TEMPERATURE, F:	328	335	349	342	344	326
GAS TEMPERATURE @ 1s, F:	187	190	184	188	190	167
OUTLET GAS TEMPERATURE, F:	230	223	227	217	222	199
DILUTION WATER FLOW, gpm:	4.49	2.59	1.63	4.26	3.57	.70
LIME SLURRY FLOW, gpm:	.00	2.81	3.97	6.01	7.83	6.51
LIME SLURRY % SOLIDS (by mass):	.0	23.0	23.0	24.0	24.0	24.0
LIME SLURRY SPECIFIC GRAVITY:	.000	1.128	1.129	1.132	1.132	1.132
ATOMIZER SPEED, rpm:	14,000	14,000	14,000	14,000	14,000	14,000
NO. OF ATOMIZER NOZZLES:						
OFF-PRODUCT AGE, hr:	48	24	24	24	24	24
OFF-PRODUCT % Ca(OH) ₂ (by mass):	12	11	7	8	2	6
OFF-PROD INJECTION RATE, lb/min:	66	33	16	66	33	33
DRY SR, FRESH LIME:	0.00	0.51	0.70	0.53	0.73	1.10
DRY SR, OFF-PRODUCT:	0.78	0.33	0.09	0.23	0.04	0.15
DRY SR, FRESH LIME+OFF-PRODUCT:	0.78	0.84	0.79	0.76	0.77	1.25
SO ₂ CONCENTRATIONS:						
INLET, ppmv(wet)	2,967	3,007	3,250	3,292	3,254	3,391
INLET, ppmv(dry)	3,314	3,161	3,477	3,579	3,424	3,498
@ 1s, ppmv(wet)	2,476	2,069	1,923	2,287	2,145	1,658
OUTLET, ppmv(dry)	2,511	2,031	2,021	2,343	2,099	1,468
NOx CONCENTRATIONS:						
INLET, ppmv(wet)	624	690	673	659	575	634
INLET, ppmv(dry)	656	688	697	692	619	663
@ 1s, ppmv(wet)	575	668	645	636	536	621
OUTLET, ppmv(dry)	568	614	612	605	536	544
SO ₂ REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	16.5	31.2	40.8	30.5	34.1	51.1
SYSTEM	24.2	35.7	41.9	34.5	38.7	58.0
NOx REMOVAL EFFICIENCIES:						
1s (EVAPORATION ZONE)	8.0	3.0	4.0	3.0	7.0	2.0
SYSTEM	13.4	10.8	12.2	12.6	13.4	17.9
ELECTROSTATIC PRECIPITATOR DATA :						
TR SET A, kV	34.8	33.9	34.9	32.8	31.0	33.8
TR SET A, mA	322.0	321.0	325.0	320.0	317.0	320.0
TR SET B, kV	36.8	35.6	36.6	35.4	34.5	35.0
TR SET B, mA	324.0	322.0	325.0	324.0	320.0	321.0
TR SET C, kV	32.6	32.4	33.2	33.6	32.0	31.8
TR SET C, mA	235.0	234.0	237.0	237.0	233.0	234.0
TR SET D, kV	43.6	42.2	44.8	41.0	48.5	40.7
TR SET D, mA	225.0	225.0	233.0	107.0	237.0	223.0
ESP POWER, kW	40.60	39.42	41.54	34.32	39.82	38.57
OUTLET OPACITY, %	2.2	3.4	.5	6.2	9.4	9.7
WING CONFIGURATION:						
NOSE POSITION, in.	29	29	29	29	29	29
ANGLE, deg.	18	18	18	18	18	18
WIDTH, in.	12	12	12	12	12	12
FLAP CONFIGURATION:						
LEFT FLAP POSITION, in.	5.00	5.00	5.00	5.00	5.00	5.00
RIGHT FLAP POSITION, in.	8.75	8.75	8.75	8.75	8.75	8.75
ATOMIZER WHEEL LOCATION:						
DEPTH, in.	9	9	9	9	9	9
DISTANCE OFF DUCT CENTER, in.	0	0	0	0	0	0

APPENDIX E - DATA ACQUISITION SYSTEM CHANNEL ASSIGNMENTS

CHANNEL NO.	SIGNAL DESCRIPTION	ENG UNITS	VOLTAGE RANGE	VOLTAGE TO ENG.UNITS CONVERSION ALGORITHM
0	SO ₂ concentration	ppm	0-5	1006.803*V-20.1361
1	NO concentration	ppm	0-5	196.992*V+4.3338
2				
3	NO+NO ₂ conc.	ppm	0-5	198.693*V+3.9739
4	O ₂ concentration	ppm	0-5	5.0998*V-0.0153
5	CO ₂ concentration	ppm	0-5	4.0*V
6	ESP inlet opacity	%	0-5	24.9215*V-26.2922
7	ESP outlet opacity	%	0-5	24.9215*V-26.2922
8	Atomizer bottom accn.	m/s/s	0-5	13.08*V
9	Atomizer top accn.	m/s/s	0-5	13.08*V
12	Atomizer current	Amp	0-5	1500*V
14	Dilution water flow	gpm	0-5	1.2729*V-1.56457
15	TR set, A, kV	kV	0-5	20.9923*V-20.1325
16	TR set, A, mA	mA	0-5	132.298*V-125.965
17	TR set, B, kV	kV	0-5	20.7598*V-19.7102
18	TR set, B, mA	mA	0-5	132.828*V-127.141

APPENDIX E (CONT'D...) - DATA ACQUISITION SYSTEM CHANNEL ASSIGNMENTS

<u>CHANNEL NO.</u>	<u>SIGNAL DESCRIPTION</u>	<u>ENG UNITS</u>	<u>VOLTAGE RANGE</u>	<u>VOLTAGE TO ENG. UNITS CONVERSION ALGORITHM</u>
20	TR set, C, kV	kV	0-5	$19.2053*V-19.0533$
21	TR set, C, mA	mA	0-5	$122.941*V-123.535$
22	TR set, D, kV	kV	0-5	$19.9939*V-20.2714$
23	TR set, D, mA	mA	0-5	$121.927*V-121.467$
24	Lime slurry flow	gpm	0-5	$4.73634*V-4.61914$
25	Inlet venturi DP	inH ₂ O	0-5	$1.33735*V-1.33980$
26	ESP inlet temp.	Deg F	0-5	$100*(V-1)$
27	Outlet venturi DP	inH ₂ O	0-5	$1.24006*V-1.23969$
28	DP across atomizer	inH ₂ O	0-5	$0.99852*V-1.00899$
29	DP across ESP	inH ₂ O	0-5	
	In vent Abs Press	in Hg	0-5	$3.75*V+16.25$
30	Inlet abs. Pressure	in Hg	0-5	$8.75*(V-1)$
31	Grid (1,1) velocity	ft/s	0-5	$799.424*V-10.067$
32	Grid (1,2) velocity	ft/s	0-5	$799.424*V-10.067$
33	Grid (1,3) velocity	ft/s	0-5	$799.424*V-10.067$
34	Grid (2,1) velocity	ft/s	0-5	$799.424*V-10.067$

APPENDIX E (CONT'D...) - DATA ACQUISITION SYSTEM CHANNEL ASSIGNMENTS

CHANNEL NO.	SIGNAL DESCRIPTION	ENG UNITS	VOLTAGE RANGE	VOLTAGE TO ENG. UNITS CONVERSION ALGORITHM
35	Grid (2,2) velocity ft/s		0-5	799.424*V-10.067
36	Grid (2,3) velocity ft/s		0-5	799.424*V-10.067
37	Grid (3,1) velocity ft/s		0-5	799.424*V-10.067
38	Grid (3,2) velocity ft/s		0-5	799.424*V-10.067
39	Grid (3,3) velocity ft/s		0-5	799.424*V-10.067
49	Sampling indicator 1			Digital
50	Sampling indicator 2			Digital
51	Sampling indicator 3			Digital
52	Sampling indicator 4			Digital
53	Sampling indicator 4			Digital
54	Wet/Dry indicator			Digital
57	Atm bot bearing temp	Deg F	0-5	See Section 1
60	Atm top bearing temp	Deg F	0-5	See Section 1
59	Master D/A ref temp	Deg F	.1V/ ^o C	0.1*V
100	Unit 5 power output	MW	0-5	175*(V-1)
101	Unit 5 coal feed rate	ton/hr	0-5	81.25*(V-1)
102	Unit 5 feed water rate	gps	0-5	37.3357*(V-1)
103	Unit 5 air flow rate	%	0-5	25.0*(V-1)

APPENDIX F - DATA ACQUISITION & CONTROL SYSTEM PROGRAM

The Data Acquisition & Control System (DACS) is operated through a control program. The control program was developed in the ASYST language. ASYST is a compiled, C-like, language with advanced mathematical features. ASYST was chosen because of the ease of data analyses and graphics generation. The control program consists of several sub-routines. These are:

<u>SUBROUTINE</u>	<u>DESCRIPTION</u>
1. 232INIT.1	Initialize RS232 communication port baud rate, parity, #start & stop bits CALL: RS232INIT.1 COM1 or COM2 port should be previously configured using RS232.DEVICE command
2. OUT	Send keyboard commands to HP-9730 interface CALL (HP Command) OUT, where HP Command is an ASCII sequence which will trigger specific action by the HP A/D & D/A interface. Ex AI25 OUT take 1 reading from channel 25 and store that reading in the serial buffer. AI25 is an HP command
3. SCAN	Get 1 value of data for specified channel using pre-specified # digits CALL: NC SCAN, where NC is a channel number.
4. SCAN5.5	Get 1 value of data for specified channel using 5 1/2-digit A/D conversion CALL: NC SCAN5.5, where NC is a channel number
5. SCAN3.5	Get 1 value of data for specified channel using 3 1/2-digit A/D conversion CALL: NC SCAN3.5, where NC is a channel number
6. SCAN.6D	Get 6 values of data for specified channel using pre-specified # digits CALL: NC SCAN.6D, where NC is a channel number
7. SCAN.3D	Get 3 values of data for specified channel using pre-specified # digits CALL: NC SCAN.3D, where NC is a channel number

APPENDIX F (CONT'D...) - DATA ACQUISITION & CONTROL SYSTEM PROGRAM

<u>SUBROUTINE</u>	<u>DESCRIPTION</u>
8. CONTROL.OUT	Send mA value to specified D/A slot & channel #'s CALL: NS NC MA CONTROL.OUT, where NS and NC are analog output slot number and channel number on the HP interface, and MA is the milli-amp value to be maintained in the process control current loop.
9. CONTROL.RPM	Process control to maintain RPM setpoint CALL: RPM CONTROL.RPM, where RPM is the current angular speed of the atomizer.
10. CONTROL.DW	Process control to maintain dilution water flow rate setpoint CALL: DW CONTROL.DW, where DW is the current value of the dilution water flow rate.
11. CONTROL.LS	Process control to maintain lime slurry flow rate setpoint CALL: LS CONTROL.LS, where LS is the current value of the lime slurry flow rate.
12. CONTROL.GF	Process control to maintain gas flow rate setpoint CALL: GF CONTROL.GF, where GF is the current value of the gas flow rate.
13. JTC-T_TO_V	Convert T,Deg C to type-J thermoelectric mV CALL: TC JTC-T_TO_V, where T is the temperature in Deg.C to be converted.
14. JTC-V_TO_T	Convert type-J thermoelectric mV to T,Deg F CALL: V JTC-V_TO_T, where V is the type-J thermoelectric voltage to be converted to a corresponding Centigrade temperature.
15. TC.REF	Read thermo-couple reference channel # and calculate thermo-electric reference mV CALL: NC TC.REF, where NC is the channel number serving as a thermocouple reference temperature input. On the HP, every 20-channel temperature card has the last channel as an indicator of the reference junction temperature.

APPENDIX F (CONT'D...) - DATA ACQUISITION & CONTROL SYSTEM PROGRAM

<u>SUBROUTINE</u>	<u>DESCRIPTION</u>
16. TC.TMP	Convert J-type thermo-electric mV from specified channel, and convert to Deg F using previously determined reference voltage CALL: NC TC.TMP, where NC is a thermocouple channel.
17. TC.AVG	Read specified channel temperature as average of 3 readings CALL: NC TC.AVG, where NC is a thermocouple channel.
18. CNVT	Convert data string from HP to numerical data CALL: NC CNVT, where NC is a thermocouple channel.
19. CNVT1	Filter out noisy A/D conversions from HP CALL: NC CNVT1, where NC is a thermocouple channel.
20. TC.SCAN	Scans wall thermocouples along a specified wall CALL: NSIDE TC.SCAN, where NSIDE is 1 number specifying the wall. For Station 1, NSIDE is 1,2,3 and 4 for the south, east, north, and west walls. For Station 2, NSIDE is 1,2,3 and 4 for the top, right, botom and left walls.
21. TIMEIT	Convert date or time information provided as a string to numerical values CALL: NOPT "TIME TIMIT, where "TIME is an ASYST keyword for obtaining time from DOS, and NOPT=1 for time and any other value for date.
22. GAS.DENSITY	Calculate gas density from pressure and temperature using ideal gas law CALL: P T GAS.DENSITY, where P is the gas absolute pressure in atmospheres, and T is the gas temperature in deg F.
23. VENTURI	Calculate the duct gas velocity from the venturi pressure drop, and the gas temperature & pressure at the venturi inlet CALL: DP RHO K VENTURI, where DP is the pressure drop across the venturi in inches, water, RHO is the gas density in lb/ft ³ , and K is the venturi constant discussed in Section 1. The constant K is such that, the gas velocity, V, DP, and K are related by:

APPENDIX F (CONT'D...) - DATA ACQUISITION & CONTROL SYSTEM PROGRAM

<u>SUBROUTINE</u>	<u>DESCRIPTION</u>
	$V = [DP \ K/RHO]^{0.5}$
23. FT	Specify floating point format for printed output CALL: N FT, where N is the desired number of digits after the decimal point. The total field of the floating point number is fixed at 7.
24. FT.LIN	Print specified series of process parameters CALL: i j k l .. N FT.LIN, where i, j, k, and l are indices of the array REC to be printed, and N is the total number of parameters to be printed. All process parameters are stored in the array REC by the control program.
25. PRNT.LIN	Count # of printed lines and issue form feed at end of page CALL: PRNT.LIN. Every call to PRINT.LIN increments the line counter by 1. When the line count reaches 66, a form feed is issued, and the line counter is reset to 0.
26. GAS.COMP	Scan gas analyzer outputs and maintain peak for each species and sampling location CALL: GAS.COMP. GAS.COMP performs several functions. These are: (i) scan sample select indicators (channels 49 to 53) to determine active sampling location, and determine from the wet/dry indicator if the measurements are in wet or dry modes, (ii) obtain current readings from SO₂, CO₂, O₂, and NO_x analyzers, and (iii) maintain the peak value for each species, sampling location, and wet or dry measurement mode.
27. READ.INP	Reads inputs from keyboard, and highlight input values on the monitor. CALL: READ.INP
28. INIT.SETPT	Initializes parameters and setpoints used for process control. The following are the initial values:

APPENDIX F (CONT'D...) - DATA ACQUISITION & CONTROL SYSTEM PROGRAM

<u>SUBROUTINE</u>	<u>DESCRIPTION</u>
	Adiabatic Saturation Temperature, TAST=130 F Lime slurry specific gravity, RHO.SL=1 Lime slurry solids fraction, CA.FRN=0.0 Gas flow rate setpoint, GF.SP=25,000 acfm Atomizer angular speed, RPM.SP=14,000 rpm Dilution water flow rate setpoint, DW.SP=0.0 gpm Dilution water process control mode, MDW=0 (maintains fixed gpm; MDW=1 maintains fixed approach to saturation)
INIT.SETPT (CONTD...)	Lime slurry flow rate setpoint, LS.SP=0.0 gpm Lime slurry process control mode, MLS=0 (maintains fixed gpm; MDW=1 maintains fixed dry stoichiometric ratios)
29. SETPT	invokes menu for resetting any of the following parameters used in process control: Time between wall thermocouple printouts, adiabatic saturation temperature, lime slurry specific gravity, solids percentage in lime slurry, gas flow rate setpoint, atomizer rpm setpoint, process control mode for dilution water, dilution water setpoint either as gpm or approach to saturation depending on MDW value, process control mode for lime slurry, lime slurry setpoint either as gpm or dry stoichiometric ratio depending on MLS value, and current loop reset values for all four process control loops.
30. GFKEY	Controls toggling of gas flow rate between automatic or manual modes using Function key
31. DWKEY	Controls toggling of dilution water flow rate between automatic or manual modes using Function key
32. LSKEY	Controls toggling of lime slurry flow rate between automatic or manual modes using Function key

Using the above subroutines as building blocks, the control program performs the task of acquiring the data and performing automatic process control as needed, and recording key process data on floppy disk and on a line printer.

APPENDIX G - ATOMIZER RELOCATION PROCEDURE

1. Lift atomizer from its stand and insert it in the hole provided for in the atomizer station from which it is being moved.
2. Move the stand to the new location using the hoists built into each station, and then move atomizer to new station and rest on stand.
3. Disconnect the flow meters and instruments from old location and reconnect them on new location.
4. Connect power wiring to atomizer in new location:
  - a. place lock breaker in MCC (Motor Control Center in Control Room) in open position, and disconnect atomizer power from MCC,
  - b. disconnect atomizer power cable and conduit from original atomizer station, and
  - c. reverse steps a and b above to re-install atomizer power wiring at new location.
5. Connect atomizer instrument wiring in new location
  - a. remove disconnect plug from original atomizer station terminal box,
  - b. remove disconnect receptacle and associated wiring from atomizer station terminal box,
  - c. remove SSL.107 and associated wiring from atomizer station terminal box,
  - d. disconnect conduit and cable for the following equipment from the atomizer station terminal box:

FIT-117, FV-104, TV-114, PDIT-131, FIT-115, and atomizer lube oil system,
  - e. re-install disconnect receptacle and associated wiring in terminal box of new atomizer station,
  - f. re-install SSL.107 and associated wiring
  - g. re-install conduit and cable for the following equipment in terminal box of new atomizer station:

FIT-117, FV-104, TV-114, PDIT-131, FIT-115, and atomizer lube oil system,

APPENDIX G - ATOMIZER RELOCATION PROCEDURE
CONTINUED

- h. insert disconnect plug-in to receptacle on new atomizer station terminal box.*

The following reference drawings will be required for the move:

EW105, EW106, EW151, EW152, PA100, PA101, PD101, PD102, PD103, PD104, and PD105.

APPENDIX H - LIME SLAKER OPERATION

Initial Procedure

1. Turn on the slaker drive and run enough water into slaker so that water agitation is audible.
2. Open the slaking water supply to the pre-determined feed rate, and then turn on the lime feed (the lime silo slide gate must be open).
3. Turn off the lime and water feeds when the slaking tank is about half full, and the slurry temperature is about 150 F, but allow the slaker to continue running.
4. Now resume feeding lime and water. When slurry just begins to enter the screen, and the slurry temperature is about 160 F, turn off the feeds once more, but leaving the slaker running.
5. After the slaker has run without feed for 4 or 5 minutes, activate the screen, screen spray and grit screw.
6. Turn on the feeds. Adjust the feed rates of lime and water until the slaking temperature is in a desirable range (160 to 180 F).
7. Set the high temperature controller at 180 F.
8. Adjust the screen spray to the lowest water rate that gives satisfactory results

Normal Procedure

1. Verify that the drain plug installed in slaking tank, and that the slaking tank has sufficient water as in Step 1, above.
2. Turn on the slaker drive, and then the feeds.
3. When the slaker is full, stop the feeds, but allow the slaker to operation to continue until the slaking temperature is in the desirable range.
4. Activate the screen, screen s, grit screw, and agitators in slurry holding tank.
5. Re-start lime and water feeds and continue slaker operation until the desired slurry level in the holding tank is reached.

ic Starting Procedure

When all switches on the slaker control panel are set for automatic operation, the slaker will start automatically start when the slurry level in the holding tank falls below the low level, and re-start when the slurry level has reached the high level.

Stopping and Emptying Procedure

1. Stop water and lime feeds.
2. Open the drain valve.
3. Stop the screen, screen spray, and the grit screw.
4. Turn off slaker drive.
5. wash off the screen with a hose.

Slurry Pump Starting Procedure

1. Open suction and discharge valves.
2. Open the lime loop discharge valve.
3. Start-up the pump (A or B).
4. Adjust slurry pressure to 40 psig using loop discharge valve.