Second Quarter, 1997

Visitors

In Quarter 2, 1997, the facility hosted 164 visitors bring the 1997 total to 1033. When added to the 1996 of 319 this brings the total for the project to 1352 documented visitors. In Quarter 2, 1997, groups came many foreign countries including Brazil, Japan, China, Korea, South Africa, Thailand, and Indonesia. Other groups represented U.S. firms interested in the technology, U.S. engineering societies and community groups.

Operations:

Two gasifier runs totaling 420.5 hours were completed in Quarter 2, 1997. Table 1 below details the runs that were achieved during the quarter and lists the reason for the termination of each run.

TABLE 1
Gasifier Runs, Shutdown Causes
Quarter 2, 1997 Operation (April, May and June 1997)

Run Number	Duration (Hours)	Turbine On Syngas (Hours)	Shutdown Cause
26	13.82	0	Manual gasifier trip due to syngas leaking into the out of the lean amine storage tank. Lean amine pump failure lead to backflow of amine absorber vessel liquid level and syngas.
27	406.7	320.63	Manual gasifier trip due to raw syngas leaking into the clean syngas stream to the combustion turbine.
Total	**420.52**	**320.63**	

Specific operational experiences are detailed below.

ALTERNATE COAL

Alternate coal pretesting began with the introduction of Island Creek coal from the Kentucky #11 seam into the gasifier at 3:00 am on May 19. The transition was complete and the unit was operating on 100% Kentucky #11 by 12:00 noon that day. The plant continued to operate on 100% Kentucky #11 for 48 hours until 12:00 noon on May 21 when we decided to interrupt the pretest and begin the transition back to the base coal, Pittsburgh #8. The pretest was interrupted to address problems presented by this new coal in the slurry preparation and acid gas removal systems while we still had sufficient Kentucky #11 left for some operation once the problems were resolved.

Slurry preparation was constrained to operate at or below 59% concentration on the Kentucky #11 coal because of the limitation imposed by the shaker screens at the rod mill discharge. This slurry concentration constraint limited plant output and increased heat rate. Shaker screens with larger openings were ordered which will permit operation at higher slurry concentration while still providing slurry feed pump protection consistent with the pump vendor's recommendations.

Residual H_2S levels in the clean syngas were excessive with the higher sulfur Kentucky #11 coal. This was primarily because of high absorber operating temperatures due to fouling of the solvent coolers. On-line attempts to clean the lean amine coolers were unsuccessful.

One complete data set was gathered during a 12 hour steady state period in this first campaign of the Kentucky #11 pretest. The data was gathered at 58.3% slurry concentration and at a Combustion Turbine output of 175 MW (91% of rated load). Net plant output was 228 MW at a heat rate of 9510 BTU/KWH. This compares to a full load net output of 249 MW at a heat rate of 9140 BTU/KWH on Pittsburgh #8 under similar ambient conditions with the same plant configuration.

A complete report on the Kentucky #11 Pretest will be issued once the remainder of the coal is processed and the data is evaluated.

AIR SEPARATION

The ASU continues to operate very well meeting all of the purity and flow requirements. Performance testing of the ASU was completed in May and reported in June, 1997. The results of the ASU performance tests indicate that the ASU met its purity and flow requirements; but is slightly high on the guaranteed total power consumption. The ASU is approximately 0.9% higher in power consumption than contract guarantees. A conference with air products is scheduled for July, 1997 to deal with the excess power consumption issue.

SLURRY PREPARATION

Shaker screen plugging problems persisted with both the base coal, Pittsburgh #8, and the Kentucky #11 test coal. New shaker screens with larger openings were ordered. The new coal screens are expected to greatly reduced plugging problems while still providing the slurry feed pump protection recommended by the pump vendor.

The new combination of natural rubber liners and full sized rotors was installed in an attempt to extend the life of the mill discharge slurry pumps. This combination has been in service on the "A" mill throughout Run 26 and has accumulated 400 hours of run time without indication of significant deterioration. These results are promising. In addition, a test of a hard iron centrifugal slurry pump is planned for July.

With the exception of these and some other minor issues, the slurry preparation system has performed well for the quarter.

GASIFIER

A second minor modification was made to the process feed injector in an attempt to improve carbon conversion. The data suggested there was a slight improvement (0.4%). No improvement was detectable in the quantity or quality of the slag and fines.

The new higher quality refractory hot face liner was in place for operation during this quarter. The two complete data sets gathered during the second quarter indicated that the new liner should provide over 2 years of service, meeting the target expectations.

HIGH TEMPERATURE SYNGAS COOLING

Both gasifier runs during the second quarter were terminated due to tube leaks in the remaining Raw Gas / Clean Gas Exchanger shell.

Shortly after startup of gasifier Run 26 (April 24), the leak detection analyzers were placed in service, and they immediately showed that the Raw Gas / Clean Gas Exchanger was leaking. The combustion turbine had not yet been transferred to syngas fuel. An orderly shutdown of the plant was in progress when a problem in the AGR system necessitated an immediate shutdown (see the AGR system discussion for details). The cause of the tube leak was that a plug had been omitted from a tube which had been intentionally punctured during the previous outage. There was also associated erosion damage in adjacent tubes. The damaged tubes were plugged. Several pin-hole leaks were also found in Raw Gas / Nitrogen Exchanger tubes during hydro test, and these, too, were plugged. The remaining three gas to gas exchangers (one Raw Gas / Clean Gas heat exchanger and two Raw Gas / Nitrogen exchangers) were returned to service for the next run.

Gasifier Run 27 began on May 9 and was terminated on May 26 after the analyzers indicated another leak in the Raw Gas / Clean Gas Exchanger. Deposits were again found on Combustion Turbine components, although the damage was not as severe as that found after Run 25. The first stage nozzle deposits consisted mostly of iron with a layer of typical coal ash constituents. The following is a brief chronology of the run and a likely explanation of the cause of the turbine damage.

> During the first nine hours of run 27, operators encountered weak slurry concentration and unusually high oxygen purity, both of which led to excessive gasifier temperatures. This, accompanied by the low velocities normally associated with startup, caused many tubes of the remaining gas to gas exchangers to plug with ash. When the unit was brought to full load, velocities were excessive in the tubes which remained open, evidenced by very high differential pressures throughout the run.
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> During the first five days of the gasifier run, combustion turbine exhaust temperature spreads (an indication of deposits) were erratic and high, but by May 16, the spreads were steady and in a normal range. The system had been exposed to air during the previous outage, and it is possible that this caused some scale to be exfoliated from the pipe walls. This scale may have been ingested into the turbine and caused some of the iron deposits.
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> On May 22, following the first Kentucky #11 campaign, the turbine was transferred to distillate fuel, and the clean gas system was opened to attempt cleaning the AGR solvent

coolers. When the AGR and water wash systems were restarted, the AGR solvent and water wash column filters plugged quickly, indicating there was an excessive amount of material (probably pipe scale) in the system. Following transfer of the Combustion Turbine back to syngas on May 24th, load was increased relatively rapidly and the combustion turbine temperature spreads were excessive, near the turbine trip point. It is likely that some additional iron entered the combustion turbine and deposited during this period.

Near noon on May 26, the analyzers gave the first indication of a possible gas to gas exchanger leak, and the combustion turbine was quickly transferred to distillate fuel. A careful investigation of the data trends suggests the combustion turbine may have operated for up to 1¾ hours with a minor tube leak. This was probably the source of the small amount of material containing typical coal ash constituents found on the combustion turbine's first stage nozzle deposits. Subsequent analysis of the failed tube indicated the failure was caused by erosion. This was probably due to the high velocities resulting from the large number of tubes which had plugged with ash at the beginning of the run.

The Combustion Turbine Inlet Strainers had been removed from service in January 1997 when cracks were observed in the pressure vessel body. Project personnel decided that the turbine would not be operated on syngas fuel without the inlet strainers in the future.

Project personnel also decided that all exchangers that could possibly cause contamination of clean syngas or nitrogen going to the combustion would be removed or bypassed. These were: the first and second stages of the raw gas/nitrogen exchangers, the first stage of the raw gas/clean gas exchanger, and the clean gas preheater located in the low temperature gas cooling section of the plant. The removal of this equipment is expected to result in a 285 BTU/KWh heat rate penalty. Other changes associated with the removal of these exchangers to accommodate the additional heat rejection are described in the to low temperature gas cooling section of this report.

The gasifier is expected to return to service the first week of July.

LOW TEMPERATURE GAS COOLING (LTGC)

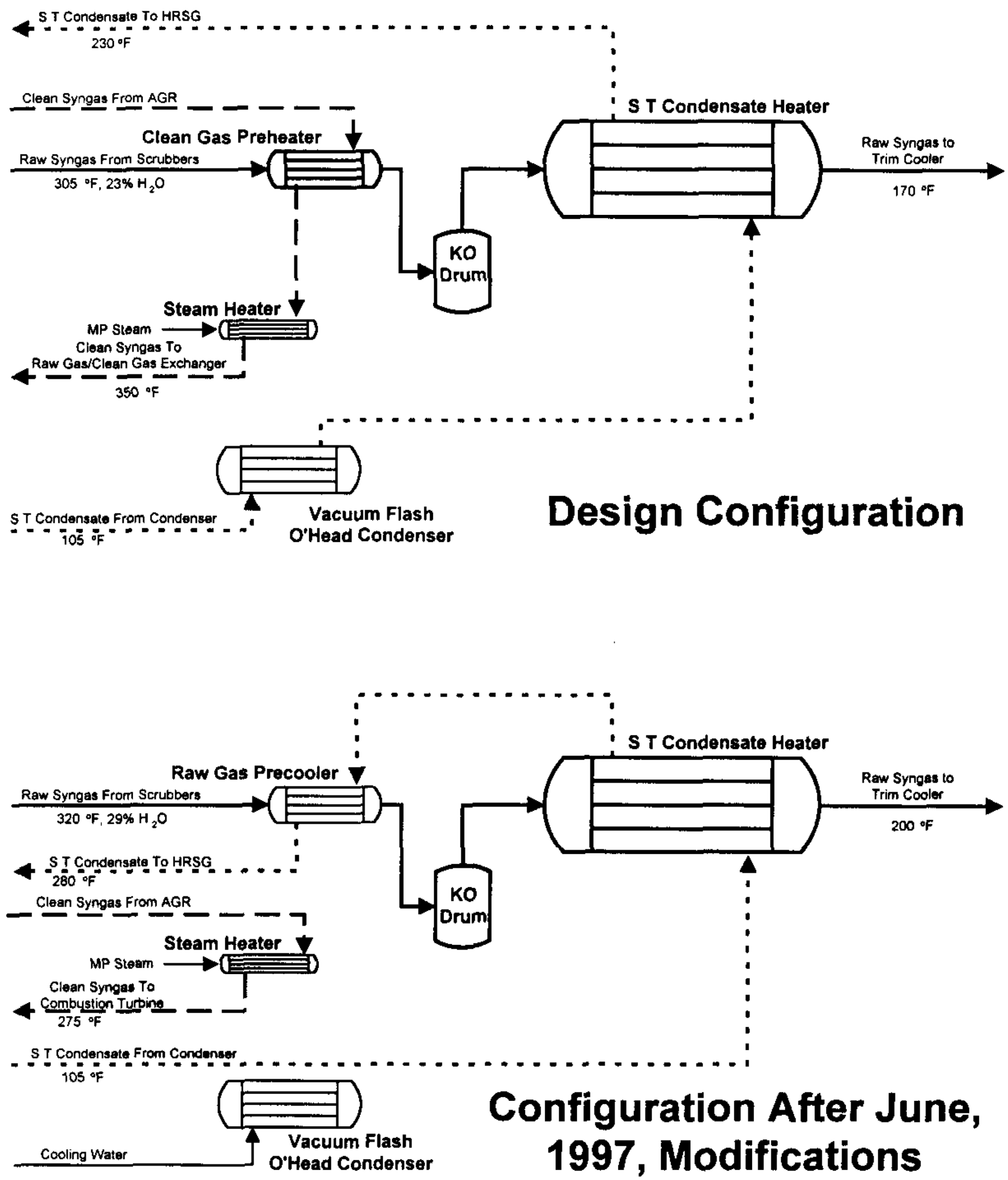
Modifications were also made in the low temperature gas cooling system as a result of the damage to the CT following Run 27:

1) The Clean Gas Preheater (which exchanged heat between the raw syngas leaving the syngas scrubber and the clean syngas) was reconfigured to avoid damage to the CT from a potential tube leak. Although no leak, thinning, pitting, or cracking of any tube in the clean gas preheater had ever occurred, and the raw gas entering the Clean Gas Preheater had been through the syngas scrubbers to remove virtually all particles, experience with leaks in the raw gas / clean gas exchangers and resulting damage to the combustion turbine convinced the project that bypassing the Clean Gas Preheater was advisable.

2) Cooling flows had to be reconfigured for the Vacuum Flash Overhead Condenser, Clean Gas Preheater, and Steam Turbine Condensate Heater to accommodate the additional heat rejection from removal of the gas to gas exchangers in high temperature gas cooling (38 MMBTU/Hr) and bypassing the Clean Gas Preheater (19 MMBTU/Hr). Steam Turbine condensate was replaced with open loop cooling water on the Vacuum Flash Overhead

Condenser. This left the steam turbine condensate with more heat rejection capacity, so, after exiting the Steam Turbine Condensate Heater, it replaced the raw syngas on the tube side of the Clean Gas Preheater (now referred to as the Raw Gas Precooler).

Low Temperature Gas Cooling - Front End



The figures below show the configurations before and after the modifications.

ACID GAS REMOVAL

Although able to meet emission limits on the particular coals burned to date, the performance of the AGR system has not met design expectations and may not meet the more stringent 1998 emissions limits. During the May gasifier run, the overall removal efficiency of the AGR system deteriorated resulting in the plant approaching permitted emissions limits. The deterioration in the performance of the AGR system was traced to an increase in solvent temperature caused by biological fouling of the solvent coolers. The performance of the AGR system was restored to levels experienced earlier in the project when the solvent were cleaned by hydro lazing. CO2 slippage increases at lower temperature while H2S slippage decreases with decrease in MDEA/syngas temperature. Increased attention to the chlorination of the open loop cooling water system is expected to help maintain AGR system performance. Further investigation of the performance of the AGR system is planned to determine why the system removal efficiency is less and why the sensitivity to increased solvent temperatures is more than anticipated in the original design.

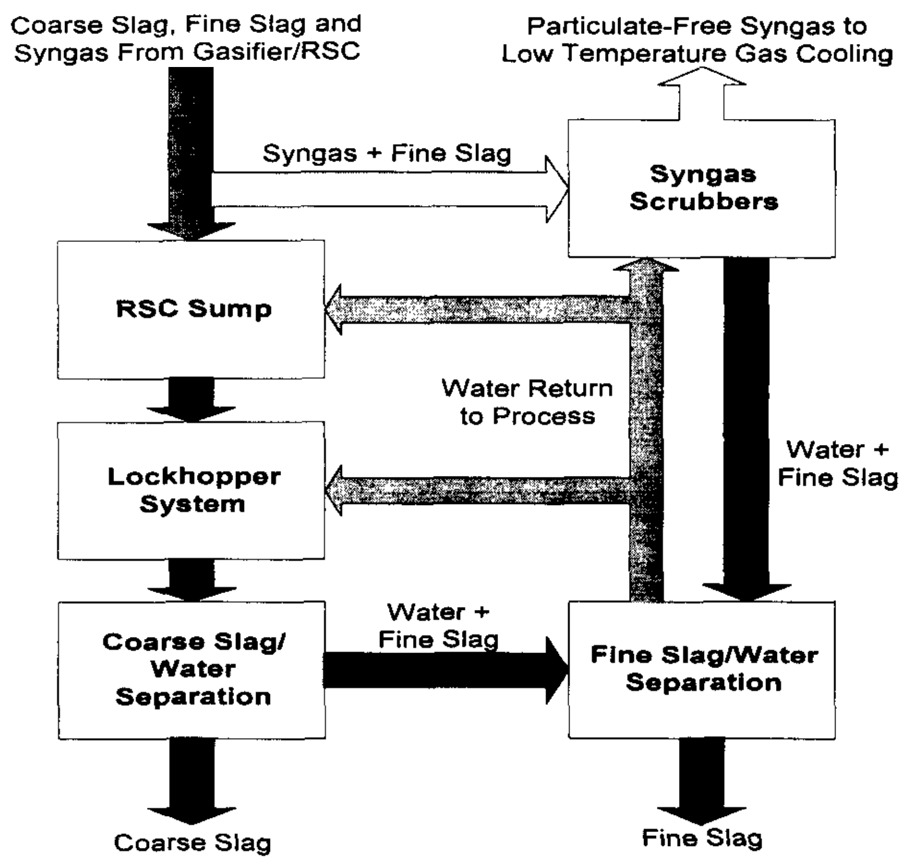
The "B" lean solvent pump tripped during run 25. Loss of lean solvent pressure in the pump discharge line permitted syngas from the absorber to back flow through the pump pressurizing the solvent tank with syngas. The syngas pressure in the solvent tank vented through pressure relief devices on the tank resulting is a gas release. The gas release was detected by area monitors and the operators terminated the run. Investigation revealed that a startup line around the pump check valve was left in the open position. To prevent a recurrence, a backup check valve that cannot be bypassed was installed in the common line downstream of both lean solvent pumps. The gases which expanded backward through the pump caused the pump and motor to over speed in the reverse direction. The motor failed due to over speed and was replaced. The original cause of the motor trip is believed to be current unbalance detected by the electrical protective relay. The trip point of the current unbalance function was increased from 4% to 10% unbalance.

Presently COS is the major sulfur carrier remaining within the unit's treated syngas. The slippage for COS is approximately 98%. This means that COS constitutes approximately 80% or more of the total sulfur remaining in the treated syngas. To reduce COS leaving the present AGR unit, we shall begin testing of MDEA upgrading to Union Carbides Ucarsol HS 104B. The initial theoretical criteria for solvent upgrade have been encouraging and predict solvent performance that could possibly meet future sulfur emissions limitations. In addition, H2S in the acid gas is expected to increase.

SULFURIC ACID PLANT

The sulfuric acid plant continues to operate well at steady state conditions. Turn down rates on the gasifier coupled with lower than design sulfur coals present some operational problems and require supplemental heat addition. A few minor duct modifications are being considered to ease operation in turn down cases. On Pittsburgh #8 coal, the acid plant is producing approximately 105 tons per day of 98% sulfuric acid.

SLAG HANDLING, FINES REMOVAL, AND PROCESS WATER SYSTEMS



Process Water Systems, Fine and Coarse Slag Handling

Since carbon conversion has not improved significantly, the fine slag/water separation system performance continues to be marginal, and the slag handling system continues to be labor intensive. Design concepts are being reviewed for modifications in these areas.

Syngas Scrubber performance continues to be acceptable. Two additional gasifier trip points had to be added to each scrubber because of the higher temperatures we will encounter after the removal of the Steinmuller gas to gas exchangers.

Lockhopper reliability continues to be high. Some periods of high Lockhopper temperature occur which cause excessive steaming during Lockhopper dumps and upsets to the process water system levels and flows. We are trying to determine the cause of these high temperature excursions.

BRINE

During the beginning of the second quarter the brine unit had poor reliability and performance but has improved and is running well during the latter part of this quarter. The key issue areas have been grey water evaporator vapor blower (GWEVB) corrosion, forced circulation evaporator condenser (FCEC) corrosion, crystallizer centrifuge (CC), and general corrosion in brine area.

To answer the GWEVB corrosion issues a blower was modified by coating the impellers with upgraded wear resistant coating. Also, new impellers of an upgraded metallurgy have been ordered. Although these blower changes are expected to extend blower life, it is unclear whether or not acceptable blower life can be achieved. An alternative design using low pressure steam supply to the blower discharge as a backup to the blowers is in design and will be tested in Quarter 3.

Brine mist carry over has caused serious corrosion problems in the FCEC. The condenser has been re-tubed twice with the existing metallurgy. A new condenser made of titanium Gr2 is on order and is tentatively scheduled for installation at the end of the third quarter.

Redesign and automation of the piping to and from the crystallizer centrifuge has been implemented. DCS controlled line flushes and line dynamics were changed for more free flow and to minimize line clogging. A vibrator installed on the centrifuge chute clears the chute every 30 seconds automatically. This configuration has provided smooth operation for the CC and is presently running well.

There has been corrosion in the brine area piping. This has been due to chemistry and erosion. Teflon lined piping has replaced most of the previous piping in the brine concentration area. This will provide longer pipe life.

The forced circulation evaporator, crystallizer flash drum, evaporator vapor blowers and crystallizer centrifuge received extensive attention during the second quarter due to corrosion, wear, and pluggage issues. The unit is running at this time and is consistently producing crystals.

COMBINED CYCLE

During gasifier run 27 beginning on May 9 and ending on May 26, 1996, power block emissions and performance tests were completed. The preliminary results indicate that the corrected power block output is .5% better than the guarantee and that the corrected power block heat rate is 1.6% better than the guarantee. The finalized report is expected to be completed in September.

A gas to gas heat exchanger failure was detected on May 26 after which the operators transferred the combustion turbine to distillate and began flaring gas (see high temperature gas cooling for details). The CT was shut down shortly after transferring to distillate. Due to the high combustion turbine exhaust gas temperature spreads observed prior to shutdown, the combustion turbine was declared unavailable and inspected. Based on the inspection, the combustion liners, six of the fourteen transition pieces, and the first stage nozzles were sent to General Electric's Houston Service Center for cleaning and repair. In addition to cleaning, the first stage nozzles required weld repair, heat treating and re-coating. In addition to the immediate fouling caused by the heat exchanger failure, it is likely that a low level of contamination causing cumulative fouling was also occurring. See the section on high temperature gas cooling for a description of modifications made to the high temperature gas cooling sections to eliminate the possibility of combustion turbine damage due to heat exchanger failure.

Originally, two strainers were provided to protect the combustion turbine from foreign object damage and from construction debris that might not have been removed by the line clearing procedures that are a normal part of the commissioning process. One of these strainers is located just ahead of the combustion turbine nitrogen valves and another is located just ahead of the combustion turbine syngas valves. These strainers were fitted with 40 mesh elements which will trap particles larger than about 350 microns. In December 1996, cracks in the bodies of the strainer pressure vessels were observed during routine inspections. These cracks were traced to limitations in the casting process used to manufacture the strainer bodies. In January 1997, a decision was made to replace the existing cast stainless steel strainer bodies with fabricated stainless steel bodies. Because of the long lead time of the improved strainers and because the combustion turbine had been in service long enough for residual debris to have been eliminated, General Electric and Tampa Electric Co agreed to operate without strainers until the new strainers arrived. The new strainers arrived and were installed during the outage between run 27 and run 28. Also, instrumentation was added to sense high differential pressure across the strainers and to automatically initiate a transfer from syngas to distillate firing. The new strainers are expected to afford some protection from particulate contamination.

Fuel and nitrogen valves continue to be a source of delays during startups and have caused unnecessary combustion turbine shutdowns during transfers to and from syngas and distillate fuels. General Electric and its suppliers continue to work toward solutions.

CONTROL SYSTEM

The distributed control system (DCS), PI data historian emergency shutdown system (ESD) and GE turbine controls were 100% available. The 6 month DCS availability test on the Bailey Infi 90 controls was completed on 4/21/97 (100% availability). Automatic generation control from Tampa Electric's system operations center was tested under conditions of distillate firing. Automatic chlorination controls for the open loop cooling water system were implemented, but not tested. The Modus data link between the combustion turbine controls and the DCS was optimized to allow faster data transfer. Leak detection logic was added to give quick operator warning for heat exchanger tube leaks (H_2S, CO, COS). Brine controls continued to be developed, implemented, and tested as the brine system was enhanced. Water balance calculations were added to assist engineers and operators with process water balancing. Controls were re-worked on the DCS and ESD as a result of the removal of the gas/gas heat exchangers. New process condensate controls were added to provide water to the carbon scrubbers. All cascade loops were modified to incorporate bumpless transfer from auto to cascade.

The alarm optimization team is continuing to create smart alarm modifications and reduce nuisance alarms. This task is anticipated to end in 1998.

Graphic display enhancements are still being performed as operators and engineers make suggestions.

Data link additions and corrections continue to be made on the combustion turbine, steam turbine and ESD Modus data links.

There were no ESD hardware failures. DCS I/O module failures still occur occasionally but are declining with time.

HOT GAS CLEAN UP

During the second quarter we continued preparing for the attrition test. The skip hoist load cell was re-calibrated by loading a known amount of sorbent into the skip hoist and re-scaling the load cell. We also calculated the sorbent density to verify that the volume of the regenerator sorbent lockhopper could be removed with 2 full skip hoist loads.

While transferring sorbent from the regenerator to the lockhopper, the regenerator outlet rotary feeder kept tripping. The feeder was removed and the clearances adjusted to fix the tripping problem. We still need to develop a set of curves for feeder speed vs sorbent flow before continuing with the attrition test.

The test will be attempted again when the gasifier is back on line and nitrogen purge pressure available. Before continuing with the tests the following items need to be completed:

1. Verify lockhopper volume
2. Remove approximately 1500 pounds of sorbent from system
3. Inspect regenerator outlet lockhopper to verify volumetric calculation in conjunction with the skip hoist volume calculation.