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SECTION I

PROJECT DESCRIPTION

I. PROJECT DESCRIPTION

Tampa Electric Company's Polk Power Station Unit 1 (PPS-1) Integrated Gasification Combined Cycle (IGCC) demonstration project uses a Texaco pressurized, oxygen-blown, entrained-flow coal gasifier to convert approximately 2000 tons per day of coal to syngas. The gasification plant is coupled with a combined cycle power block to produce a net 250 MW electrical power output. Coal is slurried in water, combined with 95 percent pure oxygen from an air separation unit, and sent to the gasifier to produce a high temperature, high pressure, medium-Btu syngas with a heat content of about 250 BTUs/cf (HHV). The syngas then flows through a high temperature heat recovery unit which cools the syngas prior to its entering the cleanup systems. Molten coal ash flows from the bottom of the high temperature heat recovery unit into a water-filled quench chamber where it solidifies into a marketable slag by-product.

Approximately 10 percent of the raw, hot syngas at 900°F is designed to pass through an intermittently moving bed of metal-oxide sorbent which removes sulfur-bearing compounds from the syngas. PPS-1 will be the first unit in the world to demonstrate this advanced metal oxide hot gas desulfurization technology on a commercial unit.

The remaining portion of the raw, hot syngas is cooled to 100°F for conventional acid gas removal. This portion of the plant is capable of processing 100 percent of the raw syngas.

Sulfur-bearing compounds from both cleanup systems are sent to a double absorption sulfuric acid plant to produce a marketable, high-purity sulfuric acid by-product.

The cleaned medium-BTU syngas from these processes is routed to the combined cycle power generation system where it is mixed with air and burned in the combustion section of the combustion turbine. Nitrogen from the air separation unit at 98 percent purity is simultaneously injected into the combustion section to reduce the formation of nitrogen oxides and to enhance mass flow through the combustion turbine for power augmentation. This combination results in the generation of about 192 MW of electricity from the combustion turbine-generator.

Heat is extracted from the expanded exhaust gases in a heat recovery steam generator (HRSG) to produce steam at three pressure levels for use throughout the integrated process. The majority of this steam, at high pressure, together with high pressure steam generated in the gasification process, drives a steam turbine-generator set to produce additional electrical output of about 121 MW. Internal plant power consumption is approximately 63 MW, resulting in a net power output from the integrated unit of 250 MW: A simplified Block Diagram is included as exhibit C of the Appendix.

A highly modular, microprocessor-based distributed control system (DCS) will provide continuous and sequential control for most of the equipment on PPS-1. This network has been designed to communicate with other key plant control units like the combustion turbine and steam turbine control systems and the gasification system emergency shutdown system. The DCS is an important part of the IGCC facility in that it provides the control link that integrates these complex processes.

Also important to this project is the development and utilization of a valuable diagnostic and training tool in the form of a dynamic simulator. This tool was used to simulate various operating modes of plant equipment, including upset conditions that could occur within the complex systems which comprise the IGCC facility, and was invaluable during the training program for plant operators and technical personnel.

SECTION II

PROJECT HIGHLIGHTS

II. PROJECT HIGHLIGHTS

This section describes in condensed form some of the key features of the Polk IGCC Project which make it unique and contribute to the advantages associated with integrated gasification combined cycle technology.

Tampa Electric's Polk IGCC Demonstration Project is co-funded by the U. S. Department of Energy (DOE) as an important part of its Clean Coal Technology (CCT) Program, Round III. DOE is providing more than $142,000,000 in co-funding for this Project. The primary objectives of this project include the successful demonstration of commercial-scale integration of the coal gasification facility with the state-of-the-art combined cycle power island, and the demonstration of a technically and commercially viable hot gas cleanup system.

Site selection for Polk Power Station (PPS) was made with the guidance of a uniquely conceived and assembled team of experts. Tampa Electric formed a Power Plant Siting Task Force composed of prominent environmentalists, educators, and business and community leaders. Environmental impact was one of the primary drivers in the choice of allowable sites for the plant. Consequently, the property in Polk County, Florida which was selected for the plant is comprised mostly of land which had previously been mined for phosphate rock. Substantial work in the areas of mine reclamation, wetlands and uplands restoration, and establishment of a wildlife corridor were completed in conjunction with the development of the demonstration IGCC facility.

The blending of specific technologies which comprise Polk Power Station Unit No. 1 results in a highly integrated system which utilizes virtually all of the oxygen and nitrogen produced in the plant's air separation unit to meet gasifier oxygen demand and diluent nitrogen requirements for the advanced combustion turbine. The result is highly efficient, environmentally superior performance.

The syngas cooling systems make effective use of available heat within the cycle and generate supplemental steam which is integrated into the process to produce significant overall plant efficiency gains.

The innovative hot gas cleanup system on PPS-1 utilizes an intermittently-moving bed of sorbent to remove sulfur-bearing compounds from the hot syngas. The benefits include heat rate improvement as well as reduced plant power consumption as compared to the conventional process of cold gas cleanup using acid gas removal technology.

By-products from this unique combination of technologies are extracted as marketable products, primarily as slag and high grade sulfuric acid.

Finally, to integrate the control logic for this complex facility, a number of important control features were developed which include a dynamic simulator, a distributed control system, and an emergency shutdown system.

SECTION III

ENVIRONMENTAL AND PERMITTING ACTIVITIES

III. ENVIRONMENTAL / PERMITTING

The following significant events, related to the Polk IGCC Project's Environmental and Permitting requirements, occurred in 1996.

STATE ACTIVITIES

- Request to modify the Conceptual Plan for mine reclamation activities was submitted to DEP on February 22, 1996. In response to agency questions, additional information related to the reclamation modification proposal were provided to DEP on May 13, June 28 and October 8, 1996. Resolution of the proposal is pending.

CONDITIONS OF CERTIFICATION SUBMITTALS

<u>Water</u>

- Florida DEP approval of Groundwater Monitoring Plan, submitted May 31, 1994, was effective September 7, 1995. The first DOE Quarterly Monitoring Report was submitted on May 23, 1996. Quarterly Groundwater Monitoring reports commenced in 1996.

- Florida DEP approval of the Industrial Wastewater Treatment system, submitted December 13, 1994, was effective March 15, 1995. The Sampling and Analysis Plan was submitted 1996.

- The Potable Water Treatment and Supply System was submitted to Florida DEP for approval on February 17, 1995. Approval was effective April 24, 1995. Submitted the clearance items for this system and system cleared on April 2, 1996.

- Submitted the Asbestos-free Certification for the Potable water system on October 2, 1996.

- Submitted one set of the wetland reclamation final grade and cross section drawings for the site reclamation west of SR37 October 2, 1996.

- The Sinkhole Response Plan was submitted in March 1996.

- Hydrological Analysis for Conceptual Reclamation Plan (update) was submitted in May 1996.

- The Statement of Completion and Request for Transfer to Operation Entity form was submitted for the Surface Water Management System on September 12, 1996.

- The Cooling Water Reservoir Berm Failure Flood Analysis was submitted on June 3, 1996.

- The Groundwater Monitoring Well Completion Report was submitted in 1996.

- Final Construction Report was submitted on October 30, 1996.

- Amended the National Pollutant Discharge Elimination System permit in August 1996.

Chemical Management

- Certificate of Completion for the Slag Storage area was submitted on June 19, 1996.

- The Plan for Handling and Disposal of spent Sulfuric Acid Plant Catalyst for Polk Unit 1 was submitted July 1996.

- Demonstration of Financial Assurance for the Slag Storage Area was submitted on November 12, 1996.

- Final Spill Prevention Control and Countermeasure Plan was submitted in Quarter III, 1996.

Air

- Opacity Certification Report was submitted on November 6, 1996.

- Notification of Start-up Operations were submitted on May 14, and August 12, 1996.

- Notification of Initial start up syngas flaring on August 9, 1996.

- Notification of Combustion Turbine CEM and Performance Testing on June 27, 1996.

- Submitted notification regarding performance testing of Auxiliary Boiler on June 13, 1996.

- Notification of Combustion Turbine CEM and performance testing was submitted on May 24 and 31, 1996.

- Notification of actual Start-up for the combustion turbine was submitted on April 25, 1996.

- Notification of Demonstration of CEM performance and emission performance testing for the auxiliary boiler was submitted on March 12, 1996.

- Notification of Initial Start up of combustion turbine was submitted on March 11, 1996.

- Notification of initial firing of the Auxiliary boiler on January 15, 1996.

- Ambient Air Monitoring Plan was submitted and approved in October of 1996.

- Submitted the Title V Air Permit application in June 1996.

Other

- Traffic monitoring studies were submitted to Florida DOT and Polk Count for the intersections of SR37 and CRDs 640 and 630 and CR630 and Ft. Green Road, May 1, 1995. Monitoring was conducted and report submitted on April 8,1996.

- Radioactive Material License was received during the third quarter in 1996.

SECTION IV

STATUS OF MAJOR CONTRACTS

IV. STATUS OF MAJOR CONTRACTS

A. DETAILED PROFESSIONAL ENGINEERING AND TECHNICAL SERVICES

During 1996, Bechtel's engineering support was concentrated in the field, providing support to both construction and start up. Efforts included:

- resolving contractor's questions
- providing designs to support construction and start up schedule work arounds
- supporting preparation of detailed start up, shut down and operating procedures
- providing design modifications to correct operational deficiencies

Bechtel's engineering efforts were essentially complete by the end of 1996.

B. HOT GAS CLEAN UP SYSTEM DESIGN AND START-UP SUPPORT

General Electric Environmental Services, Inc. (GEESI) continued to support construction and start up during 1996 for the Hot Gas Clean Up (HGCU) system. By the end of 1996, GEESI's efforts had been reduced to a minimum, centering around support during the various testing phases. The HGCU is scheduled to be functionally tested in 1997.

C. G.E. STAG 107F ENGINEERED EQUIPMENT PACKAGE (POWER ISLAND)

The contract for the engineering, manufacture, and supply of the engineered equipment package for the Power Island was awarded to GE in November 1992. The equipment furnished under this Contract includes the following:

- One Frame 7F Single Shaft Combustion Turbine with Low NO_X combustors capable of firing fuel oil No. 2 as well as syngas

- One 229,741 KVA hydrogen cooled generator (combustion turbine)

- One tandem compound, double flow condensing steam turbine with one uncontrolled extraction

- One 156,471 KVA hydrogen cooled generator (steam turbine)

- All the engineered skids required to provide the auxiliary and accessory systems for the combustion turbine, steam turbine and the generators

- Control Cabinets

- One three-pressure, unfired Heat Recovery Steam Generator with integral deaerator. The HRSG is capable of accepting saturated steam from the gasification plant at two pressure levels and supply steam at rated conditions of 1500 psig at 1000°F and 50 psig saturated.

At the end of 1996 all major components of the power island had been delivered, installed, checked out and put into operation. General Electric continues to support the project with on-site technicians and engineers.

During the start-up of the unit, TEC had to resolve many issues. These issues are discussed in detail in section IX C, initial operation. Included in the operation section is a complete discussion of the highly publized 7FA fleet problems and their resolutions.

At the end of 1996, TEC had entered negotiations with GE to provide ongoing maintenance and technical support. TEC expects to conclude these negotiations in 1997.

D. TURNKEY AIR SEPARATION UNIT

The contract for engineering, supply, and erection of the Air Separation Unit (ASU), dated April 14, 1993, was awarded to Air Products and Chemicals, Inc. (APCI). Commissioning and start-up of the ASU began in January of 1996 and was completed in the first quarter without major incident. In April 1996, a vibration problem developed in the main air compressor (MAC) motor. The vibration problem was investigated by TEC, APCI, and the motor manufacture. The rotor was rebalanced and tested until contract vibration requirements were met. The ASU performed well throughout 1996, and all contract monies have been paid to APCI. The contract is currently opened awaiting the results of the performance test.

E. RADIANT SYNGAS COOLING SYSTEM ENGINEERED EQUIPMENT PACKAGE

The Radiant Syngas Cooling System is designed to cool the hot syngas exiting the gasifier, generate high pressure steam, and remove coal ash from the syngas stream in the form of slag. This system was commissioned in the summer of 1996 and placed into commercial operation with the balance of the plant in October of 1996. Overall, the system has performed very well, with exit gas temperatures significantly below design numbers. In addition, this system has not contributed significantly to any unit down time in 1996.

The lower than design Radiant Syngas Cooler exit gas temperature is a result of the fouling of the heat exchange surface being significantly less than anticipated. This could be a function of the specific coal being used (only one coal was used during 1996), or could be a result of design details in the heat exchanger arrangement which improved gas flow patterns. Additional studies will be performed on this temperature in 1997, including the effects of alternate fuels.

F. CONVECTIVE SYNGAS COOLING SYSTEM ENGINEERED EQUIPMENT PACKAGE

The Convective Syngas Cooling System is designed to cool the raw syngas exiting the radiant syngas cooler while raising high and medium pressure steam as well as exchanging energy with clean gas and nitrogen streams. This system was commissioned in the summer of 1996 and placed into commercial operation with the balance of the plant in October of 1996.

The system consists of two types of heat exchanger. There are two Convective Syngas Coolers which cool the syngas and raise high pressure steam. In addition, there are four stages of gas to gas heat exchangers which cool the raw syngas while heating either clean syngas or nitrogen. The heat exchangers are interconnected with double wall, water cooled piping which generates medium pressure steam.

The convective syngas coolers have performed well, operating generally within design guidelines while not contributing to any significant Unit downtime. However, there have been significant problems with the gas to gas exchangers. Early in the start-up and commissioning phase of the plant, these exchangers exhibited a consistent tendency to plug with ash on the tube side (raw gas side) of the exchanger. This pluggage resulted in several Unit shutdowns and significantly contributed to the overall downtime in 1996.

The ash pluggage of the gas to gas exchangers also led to a significant corrosion problem in the tubes of these exchangers. After extensive study was done on the plugging phenomenon, the problem was minimized through a combination of operating and physical modifications, primarily related to optimizing combinations of Raw Syngas Velocity and Gasifier Operating Temperature. However, the tubes had already been damaged from the corrosion attack and this could not be reduced. Plans were made in late 1996 to either bypass or replace these exchangers sometime in 1997.

G. TURNKEY SULFURIC ACID PLANT

The contract for engineering, supply , and erection of the sulfuric acid plant, dated June 8, 1994, was awarded to Monsanto Enviro-Chem Systems, Inc. Catalyst and acid were loaded into the appropriate vessels and tanks in early July 1996. The acid plant was prepared for first syngas in July 1996 and produced the first sulfuric acid in August 1996. Operation of the acid plant is demanding on the operation staff when the gasifier is turned down and burning a lower than design sulfur coal. Full load operation has been relatively smooth. All monies have been paid to Monsanto and a letter of credit has been issued. Contract close out is proceeding and is expected to be completed in 1997.

H. TEXACO SUPPORT SERVICES CONTRACT (REFRACTORY AND BURNERS)

Texaco provides engineering and start-up support to the Project through three separate agreements. Under the License Agreement, they continue to provide a wide variety of services. They reviewed and approved key detailed design documents, performed on-site construction inspections, and provided start-up support services. Texaco reviewed and approved the gasifier burner manufacturer's shop drawings and inspected the completed burners.

Under a separate Technical Services Agreement (TSA) they have provided a variety of specific, as-needed services. For example, a Texaco representative provided day-to-day advise during the detailed design effort in Bechtel's Houston office. They helped in defining and setting up the on-site laboratory. In 1996, they helped write the operating procedures for the gasification portion of the plant.

Texaco, through a separate contract performed the detailed design of the gasifier refractory system. The effort also included inspection of the refractory at the manufacturer's shop. In 1996 they provided oversight of the refractory system installation.

For 1997, Texaco will continue to technically support the project on an as needed basis to insure successful operation of the gasification system.

I. DISTRIBUTED CONTROL SYSTEM

The Bailey Infi-90 Distributed Control System (DCS) has performed well during 1996. No gasifier or plant trips were caused by DCS module or I/O failures. The overall DCS availability in 1996 was 100.0 %.

Two systems associated with the DCS have also been successful: 1) the data storage, and 2) retrieval system and the operator training simulator. The Polk plant would not be running as well as it is today without these systems.

- Data storage and retrieval is done by a product called Plant Information Systems (PI) from Oil Systems Inc. Data storage has been almost 100% reliable, and retrieval is easy in several different formats (graphs, tables, spreadsheets).

Although the DCS has performed well, the required level of technical support has been higher than expected to achieve these results. A full-time team with some supplemental help worked throughout most of 1996 to address the following issues:

- DCS module infant mortality was fairly high in the Commissioning Phase, but failure rates have declined dramatically. All failed modules were replaced under warranty.

- Initially there were over 8000 possible alarms, and at times during the Commissioning Phase over 1000 of these were simultaneously active. Such information overload causes alarms to be ignored. A separate "alarm team", formed late in the Commissioning Phase, reduced the number of alarms to about 4000. Further reduction in the number of possible alarms and prioritization of the remaining alarms is still in progress.

- Conveying information which can be quickly and easily interpreted for split-second decision making is always a challenge. To meet this challenge, it has been necessary to improve plant diagnostics by adding more "first out" indications, dedicated displays, and ready lists. Graphic displays have also been modified to be more concise and easily readable. These efforts will undoubtedly continue into the foreseeable future.

- The data links between the DCS and both CT and ST Mark V control systems have been troublesome. Making changes is particularly hard. (In contrast, the data link between the DCS and the Triconex Gasifier Safety System has worked very well.) Also, working on the Mark V and GE's user interface is difficult. We must still rely more heavily on GE than we would prefer at this stage of operation. It would have been preferable to have done as many of the turbine control functions as possible directly in the DCS.

- Almost all logic and configuration errors have been eliminated, initial tuning has been done on all control loops, and some optimization has been done. However, initial operation and tuning efforts have shown that new or modified control logic will be necessary for several plant areas such as:

  -- Overall plant load control
  -- Combustion Turbine fuel transfers,
  -- pH control in water treatment,
  -- Grey Water inventory control
  -- Centrifuge control in Brine Concentration.

J. EMERGENCY SHUTDOWN SYSTEM

The contract for engineering, design, manufacturing, assembly, and shipping of the gasifier Emergency Shutdown System (ESD), was awarded to Triconex Corporation in June 1994. The ESD includes all system hardware, software, associated interfaces, and auxiliary equipment to provide for a fully functional system. The system is known as a Triple Modular Redundant (TMR) Programmable Logic Control ESD System. It includes software to fully interface with the Bailey Controls XRS90 DCS. The ESD system chassis was shipped to Bailey Control's factory for integration testing with the DCS. Integrations with the DCS completed in April 1995 with completion of shipment to jobsite occurring in May 1995. The ESD system underwent final configuration checkout based on system start-up schedules with completion occurring in July 1996.

K. SIMULATOR DEVELOPMENT

The Simulator is a dynamic process simulation system for the Polk Unit 1 IGCC plant. The Simulator was used for operator training, control systems check out and tuning, engineering analysis, marketing of IGCC to potential customers and potentially, to provide training and engineering analysis for others. It was determined to be necessary because of the complexity of this integrated design, and the first of a kind integrated controls system.

The Simulator contract was awarded to Bailey Controls. Bailey and their modeling sub-contractor, TRAX, began work in February 1995. During 1996, all models were completed and the models integrated to allow the Simulator to perform as a complete operating plant. Training of plant operators also was completed in 1996 in time to support the start up of the plant. Bailey and TRAX continued to modify the system to incorporate design changes developed after the start of the model development. This contract will be completed in 1997.

The operator training simulator furnished by Bailey and TRAX, Inc was installed and checked out during 1996. A copy of the actual plant control system (DCS and Triconex hardware and software) interacts with process plant models running on seven PC's. This simulator enabled plant personnel to become familiar with plant operation before start-up and correct control system and procedural errors before they occurred in the real plant. Final simulator testing and contract closeout is expected to occur in mid 1997.

L. BRINE CONCENTRATION UNIT

Brine Concentration Unit

The brine concentration unit began processing grey water in 1996 simultaneously with the gasification plant. The brine unit is composed of two distinct units, the falling film evaporator, and the forced circulation evaporator/crystallizer/centrifuge. The following outlines the operations of each unit during 1996.

Falling Film Evaporator

The falling film evaporator utilizes falling film distillation technology using four stage centrifugal blowers as the heat source. During all of 1996 this unit performed without incurring a plant outage. However, due to high carryover of chlorides in the blower inlet, severe corrosion has occurred. This resulted in a rotating element failure. Due to this design problem, several studies were initiated to resolve the problem. A final solution is pending a cost analysis of the alternatives presently being considered.

Forced Circulation Evaporator/Crystallizer/Centrifuge.

During 1996 several problems arose with this unit. Primarily, severe and rapid corrosion was found in the forced circulation evaporator heat exchanger, resulting in several tube bundle replacements until the correct metallurgy was found. Corrosion was also found to occur in the forced evaporator overhead condenser as well.

An extensive corrosion coupon sampling program was undertaken throughout the entire brine concentration unit to evaluate the metallurgy requirements for the falling film unit as well as the forced circulation/crystallizer sections. This coupon sampling program continues in 1997.

Extensive line pluggage occurred in the forced circulation evaporator/crystallizer/centrifuge piping. This piping was redesigned to allow better flow characteristics in 1996 and will be implemented in 1997.

M. CONSTRUCTION MANAGEMENT SERVICES

Bechtel Power Corporation provided construction management (CM) services. During 1996 major emphasis was placed on completing the construction work, and supporting start-up with manpower to complete the project.

The CM team was led by the TEC on site Construction Manager. The CM team has managed the on site construction efforts effectively in order to keep the project on schedule and within an acceptable budget.

Construction was 100% complete at the end of 1996. This represented an approximate gain of 25% during 1996. All major milestones were completed on time.

Significant achievements were reached with respect to site safety;

- The project had only 3 lost time accidents in 3.4 million man-hours worked

- Continuous streaks of 650,000 man-hours, 1,741,321 man-hours and 1,237,118 man-hours without disabling injuries

- The project received the prestigious Stag Award from the Hartford Insurance Company for excellence in safety on a construction project

- The OSHA recordable rate of 1.90 was well below the industry average of over 10.0 for this type of project

This remarkable achievement was possible through good cooperation of the site zero-accident philosophy plan implemented by all contractors.

Key construction management highlights during 1996 were:

- Completion of all construction activities
- Closeout of most major construction contracts
- Completion of environmental mitigation work.
- Completion of start-up support activities

SECTION V

PROCESS DESCRIPTION

V. PROCESS DESCRIPTION

A. COAL HANDLING, GRINDING, AND SLURRY PREPARATION

Coal is delivered to the site from a coal transloading facility at Tampa Electric Company's Big Bend Station. The coal is delivered in covered, bottom-dump trucks with a 26-ton payload, with a total of about 80 trucks per day required at design rate. On the site, the trucks off-load in an enclosed unloading structure into an above-grade unloading hopper. Dust suppression sprays are provided at the top of the hopper to control dust emissions. Belt feeders transfer coal from the hopper outlets onto an enclosed unloading conveyor.

The unloading conveyor transports coal from the unloading structure up and into one of the two storage silos. A diverter gate and a silo feed conveyor provide the set-up to feed the second, adjacent silo. A dust collection system is provided at the top of the silos to collect dust at the conveyor/feeder/silo transfer points.

Coal is conveyed from the coal silos and fed to the grinding mill with recycled process water and makeup water from the plant service water supply system. The grinding mill may also be fed fine coal recovered by the dust collection system and fines recovered from Black & Grey Water Systems. Ammonia may be added to the mill for pH adjustment, if necessary. The pH of the slurry is maintained between 6 and 8 to minimize corrosion in the carbon steel equipment. A slurry additive for reducing viscosity can also be pumped continuously to the grinding mill.

The grinding mill reduces the feed coal to the design particle size distribution. The mill is a conventional rod-type system with an overflow discharge of the slurry. Slurry discharged from the grinding mill passes through a trommel screen and over a vibrating screen to remove any oversized particles before entering the slurry tank. Oversized particles are recycled to the grinding mill.

A below-grade grinding sump is located centrally within the coal grinding and slurry preparation area to handle and collect any slurry drains or spills in the area. Materials collected in the sump are routed to the recycle tank for reuse in the process.

In order to minimize groundwater withdrawal and use, water for the slurry preparation system is provided from several sources; primarily by the moisture contents of the feedstock coal, the recycled feed, and the grinding sump water. Additional makeup water to the slurry system is provided from the plant service water system. Through the collection and recycling process, there are no water discharges from the coal grinding and slurry preparation system. All water from the system is fed to the gasifier in the coal slurry.

Potential particulate matter air emissions from the coal storage bin, grinding mill, and rod mill overflow discharge are primarily controlled by the wet nature of these subsystems and by the use of enclosures for the subsystems with vents through fabric filters or baghouses. The slurry tank vents are equipped with carbon canisters for absorption of potential hydrogen sulfide (H_2S) or ammonia (NH_3) emissions.

B. GASIFIER SYSTEM

The IGCC unit uses the Texaco oxygen-blown, entrained-flow, single-train gasification system to produce syngas for combustion in the advanced combustion turbine (CT).

Coal slurry from the slurry feed tank and oxygen from the air separation unit are fed to the gasifier and sent to the process feed injector. The gasifier is a refractory lined vessel capable of withstanding high temperatures and pressures. The coal slurry and oxygen react in the gasifier to produce syngas at high temperature. The syngas consists primarily of Hydrogen (H), Carbon Monoxide (CO), water vapor, and Carbon Dioxide (CO_2), with small amounts of Hydrogen Sulfide (H_2S), methane (CH_4), argon (Ar), and nitrogen (N_2). Coal ash and unconverted carbon form a liquid melt called slag in the gasifier.

Hot syngas and slag flow downward in the gasifier into the radiant syngas cooler, which is a high pressure steam generator equipped with a water wall to protect the vessel shell. Heat is transferred primarily by radiation from the hot syngas to the feed water circulating in the water wall. High pressure saturated steam produced in this cooler is routed to the heat recovery steam generator (HRSG) in the power block area which supplements the heat input from the CT to the HRSG and increases the efficiency of the generating unit.

The syngas passes over the surface of a pool of water at the bottom of the radiant syngas cooler and exits the vessel. The raw syngas is sent to the convective coolers and then to the low temperature syngas cooling system in the CGCU system for further heat recovery and to the demonstration HGCU system. The slag drops into the water pool and is fed to the lockhopper from the radiant syngas cooler sump.

The black water which flows out with the slag from the bottom of the radiant syngas cooler is separated from the slag and recycled after processing in the dewatering system.

C. COLD GAS CLEAN UP (CGCU) SYSTEM

The raw, hot syngas from the gasifier is routed to the separate conventional CGCU and demonstration HGCU systems for appropriate treatment. The CGCU system is designed to treat 100 percent of the syngas flow for the unit, while the HGCU system is capable of treating approximately 10 percent of the syngas.

The initial treatment process for the raw syngas within the CGCU system involves the syngas scrubbing and cooling systems. The raw, hot syngas from the gasifier contains entrained solids or fine slag particles which must be removed to produce the clean syngas fuel. Also, the raw hot syngas needs to be cooled in order to be effectively cleaned in the acid gas removal unit.

The raw, hot syngas from the gasifier is first cooled in the high temperature syngas cooling system, then sent to the syngas scrubbers where entrained solids are removed. The syngas is then routed to the low temperature gas cooling section, where the syngas is cooled by recovering its waste heat to generate steam and preheat boiler feedwater.

The syngas scrubber bottoms are routed to the black water handling system. All the black water from the gasification and syngas cleanup processes are collected, processed, recycled to the extent possible, and contained within the processes. The solids that were not removed in the radiant syngas cooler sump are separated from the system as fines. There are no liquid discharges of these process waters to other systems or to the cooling reservoir.

The effluent from the black water handling system is concentrated and crystallized into a solid consisting primarily of salt called brine which is shipped off-site for disposal in an appropriately permitted landfill. Eventually it is expected that this brine will be sold as a marketable produce to the local fertilizer industry. The water separated from the salts is recycled for slurrying coal feed.

After removal of the entrained solids, the gaseous sulfur compounds (H_2S and COS) are removed from the syngas prior to firing in the advanced CT unit to control potential SO_2 air emissions. In the acid gas removal unit, the cooled syngas is first water-washed in the water wash column. Wash water is pumped to the column to remove contaminants which would potentially degrade the amine from the syngas. The wash water from the column is sent to the Amonia (NH_3) water stripper.

D. HOT GAS CLEAN UP (HGCU) SYSTEM

For the system demonstration, this unit is designed to handle 10 percent of the hot, raw syngas from the gasifier for cleanup prior to firing in the combustion turbine. The key process steps for the system are described in the following paragraphs.

Entrained fine particles in the hot syngas are removed in the primary cyclone first and sent to the black water handling system. The exiting gas is injected with sodium bicarbonate and enters a secondary cyclone where the halogen compounds in the gas are chemically absorbed. The collected solids from the cyclone are sent offsite for disposal in an appropriately permitted landfill and the syngas flows to an absorber. Plans call for developing a marketable use for these solids.

A large fraction of any remaining particulate matter entering the absorber is captured by the sorbent bed, reducing particle concentration to below 30 ppm. A small amount of sorbent fines is entrained from the absorber and collected in a high efficiency barrier filter. The barrier filter practically eliminates all fines larger than 5 microns, with 99.5 percent of particulate matter removed. The solids from the barrier filter are sent offsite for disposal. Larger fines are sieved on screens at the regenerator sorbent outlet. Fugitive fines from the screens are collected in a small, low temperature bag filter. The sorbent fines from both collection points are reclaimed offsite, as a marketable by-product.

The absorber is an intermittently moving bed reactor. The sulfur-containing syngas from the cyclones enters the absorber through a gas manifold at its bottom and flows upward countercurrent to the moving bed of sorbent pellets. The sulfur compounds, mainly H_2S in the syngas, react with the sorbent. The syngas leaving the absorber is expected to contain less than 30 ppmv of H_2S and COS.

To maintain low H_2S outlet concentrations, the absorber bed is periodically moved. A timed signal or an H_2S breakthrough control signal activates solids flow from the bottom of the absorber into the absorber's outlet lockhopper, causing the bed and the reaction zone to move downward by gravity. The displaced sulfided sorbent is replaced by regenerated sorbent from the absorber's inlet lockhopper.

The ability to regenerate and recycle the sorbent is essential for economically viable hot syngas desulfurization. The regeneration with oxygen is a highly exothermic oxidation process which requires careful temperature control. Too high a temperature will sinter and destroy the sorbent structure and reduce its ability to react with sulfur in consecutive absorption steps. Low temperature will result in sulfate formation and a loss of reactive sorbent returning to the desulfurization process in the absorber.

Another economic factor which will be investigated is the attrition of sorbent pellets. The amount of damage done to the pellets during the mechanical process of sorbent cycling will be a critical success factor for determining the HGCU technical and commercial viability.

Sulfide sorbent is fed from the absorber's outlet lockhopper to the top of the regenerator where oxidation of the sulfided sorbent occurs. The sorbent moves down the regenerator in concurrent flow with the regeneration gas. The air to recycle gas ratio is controlled to limit the gas temperature.

The final step of regeneration is accomplished at the lower stage of the regenerator where nitrogen flows countercurrent to the sorbent. This stream cools the sorbent to a temperature acceptable for downstream equipment, purges the SO_2 - rich offgas, and ensures complete regeneration without sulfate formation. The gas streams from the concurrent and countercurrent flows mix to form the recycle gas stream.

The regeneration gas recycle system operates in a closed loop with dry air as an input and an SO_2 - rich offgas as a product output. The regeneration gas recycle loop is designed as an internal diluent that reduces the oxygen concentration in the air to the desired levels and removes the heat of reaction without the use of externally provided diluents such as nitrogen. Using recycle rather than external inert diluent also enriches the SO_2 concentration of the product stream.

The heat exchanger in the recycle loop is designed to control the temperature of the regenerator inlet streams. The steam generator removes the heat generated during the regeneration reaction by cooling the recycle gas stream. The recycle compressor operates at a sufficient suction temperature to avoid H_2SO_4 condensation and a regenerative gas heat exchanger reheats the compressed gas for recycle to the regeneration process. The heat of combustion of the sulfur is transferred to the combined cycle power block through the steam generated prior to recycle compression of the recycle gas stream.

E. COMBINED CYCLE POWER GENERATION

Key components of the combined cycle power generation system are the Combustion Turbine-Generator (CTG), Heat Recovery Steam Generator (HRSG), and Steam Turbine-Generator (STG).

1. Combustion Turbine-Generator

The CT is a GE 7FA, designed for low-NO_x emissions firing syngas, with low sulfur fuel oil for start-up and backup. Rated output from the hydrogen-cooled generator when syngas is fired in the CT is 192 MW.

The syngas is delivered to the combustion turbine via control valves on the syngas fuel control skid. Nitrogen is used as the diluent to reduce the formation of NO_x in the exhaust gas. The flow of nitrogen to the combustor is regulated by valves on the nitrogen control skid.

When operating on the fuel oil backup, demineralized water is used as a diluent to reduce the formation of NO_x in the exhaust gas. The flow of fuel oil and demineralized water is controlled by a separate skid, the fuel forwarding skid.

2. Heat Recovery Steam Generator

The heat recovery steam generator recovers the combustion turbine exhaust heat to produce steam for the generation of additional power in the steam turbine. The HRSG is a three-pressure level (HP, IP, LP) natural circulation design with reheat (RH).

The HP section heats boiler feed water (BFW) and generates superheated steam for feed to the HP steam turbine. It also provides HP economized BFW to the gasification area and receives HP saturated steam from the gasification plant. The BFW systems has two (2) 100% feed pumps. One of these pumps is a developmental magnetic bearing design.

The RH section combines HP turbine exhaust with IP superheated steam and adds superheat to the mixture for feed to the IP steam turbine.

The IP section heats BFW and generates superheated steam to be mixed with cold reheat steam for feed to the RH section. The IP section also provides BFW to the gasification area and receives saturated steam from the gasification plant. During start-up or when the CT is fuel oil fired, the IP section can be used to export saturated steam to the gasification plant.

The LP section heats and de-aerates BFW for the HP and IP systems and provides saturated steam for export to the gasification plant.

3. Steam Turbine-Generator

The steam turbine is a double flow reheat unit with low pressure extraction and drives a hydrogen-cooled generator. The steam turbine-generator is designed specifically for highly efficient combined cycle operation with nominal turbine inlet conditions of approximately 1450 psig and 1000°F with 1000°F reheat inlet temperature. Rated capacity is 124.2 MW; rated speed is 3600 rpm. Expected generator output during normal operation is 121 MW.

The outlet from the last stage of the turbine is condensed by heat exchange with circulating water from the plant cooling water reservoir. Condensate from the steam turbine condenser is returned to the HRSG/integral de-aerator by way of the coal gasification facilities, where some condensate preheating occurs.

4. Condensate System

The condensate system operates in this combined cycle power plant to:

- Return condensed steam to the cycle by pumping condensate from the condenser hotwell to the de-aerator
- Condense the steam from the steam turbine gland seals and return the condensate to the cycle
- Provide sources of condensate to various miscellaneous systems
- Provide a dump to the condensate storage tank on a high hotwell level
- Provide condensate makeup to the condenser hotwell

Condensate pump operation is required during combined cycle operation. One of the two 100 percent capacity condensate pumps is always in service during normal plant operation, while the other condensate pump is in the auto standby mode.

A hotwell dump line is connected from the condensate discharge line to the condensate storage tank for returning condensate in the event of a high level in the hotwell. Condensate supply to the hotwell is by way of vacuum drag under normal operation, and by the condensate make-up pump otherwise.

The condensate pumps also supply water to the following users in the Power Island:

- Steam Turbine Exhaust Hood Spray System
- Vacuum Pump Seals
- Condensate Receiver
- Condensate Return Tank
- Gland Seal Emergency Spray
- HRSG Chemical Injection Equipment
- Closed Cooling Water Head Tank
- Feedwater Pump Seals

5. <u>Electrical Power Distribution System</u>

For plant start-up and periods when the plant is down, power is received at 230 KV and is back-fed through the generator step-up transformers with the generator breakers in the open position. This arrangement provides power to the station 13.8 KV auxiliary transformers. The station 13.8 KV switchgear distributes power at 13.8 KV to the various plant loads including the power block 4160 V and 480 V auxiliary transformers. The 4160 V switchgear provides power to the combustion turbine static starting system and to the 4160 V motors.

During start-up, power is back-fed through the CT generator step-up transformer or the steam turbine-generator step-up transformer to power up the static starting unit. Once the combustion turbine is up to speed and self sustaining, the static starter is de-energized, and the CT generator can be synchronized to the 230 KV system by closing the 18 KV CT generator breaker. Similarly, when the steam turbine-generator is up to speed, it can be synchronized to the 230 KV system by closing the appropriate 230 KV switchyard breakers first and then the steam turbine-generator 13.8KV breaker.

Once the combustion turbine is started up and the CT generator synchronized to the system, the combustion turbine-generator can provide power to all of the station loads through the station 13.8 KV power distribution systems.

F. AIR SEPARATION UNIT

The air separation unit uses ambient air to produce oxygen for use in the gasification system and sulfuric acid plant, and nitrogen which is sent to the advanced CT.

Ambient air is filtered in a two-stage filter designed to remove particulate material. The first filter stage consists of a fixed panel filter; the second filter stage consists of removable elements, which are periodically replaced. The air is then compressed in a multistage centrifugal compressor equipped with inter-cooling between stages and a condensate removal system.

The compressed air is cooled in an after cooler and fed to the molecular sieve absorbers. The molecular sieves remove impurities, such as water vapor, CO_2, and some hydrocarbons from the air. The air is filtered once more in the dust filter to remove any entrained molecular sieve particles. Hot nitrogen is used for adsorbent regeneration. It is recovered and reused as CT diluent.

The air from the adsorbers is fed to the cold box where it is cooled against returning gaseous product streams in a primary heat exchanger (PHX). A small fraction of the air is extracted from the PHX and expanded to provide refrigeration for the cryogenic process. The expanded air is then fed to the low pressure distillation column for separation.

The remaining air exits the cold end of the PHX a few degrees above its dewpoint. The air is fed to the high pressure distillation column where it is separated into a gaseous nitrogen vapor and an oxygen-enriched liquid stream. The nitrogen vapor is condensed in the high pressure distillation column condenser against boiling liquid oxygen. The liquid nitrogen is used as reflux in the high and low pressure distillation columns.

Oxygen and nitrogen are produced in the low pressure distillation column. Heat from the condensing nitrogen vapor provides reboiler action in the liquid oxygen pool at the bottom of the low pressure distillation column. The oxygen vapor is warmed to near-ambient temperature in the PHX and fed to the oxygen compressor, where it is compressed to the pressure required by the gasification unit.

Nitrogen vapor from the low pressure distillation column is warmed to near-ambient temperature in the PHX and sent to the advanced CT.

As backup to the air separation unit, a liquid nitrogen storage system is provided for system purging and maintaining low temperature in the cold box. The backup liquid nitrogen system is maintained in a cold, ready-to-start state.

The air separation unit process does not consume water and produces only minor amounts of water from condensation in the main air compressor aftercooler. This water is sent to Industrial Water Treatment (IWT). The unit requires water only for non-contact cooling purposes which is provided from the makeup water system and/or the cooling reservoir. The ASU consumes significant electric power with mac motor. This is partially recovered via the CT with N_2 injection (150 on oil vs. 192 on syngas).

G. SLAG BY-PRODUCT HANDLING

The slag handling system is designed to remove the slag that exits through the radiant syngas cooler sump. The slag consists of the coal ash and unconverted coal components (primarily carbon) that form in the gasifier.

Coarse solids and some of the fine solids flow by gravity from the radiant syngas cooler sump into the lockhopper. The lockhopper acts as a clarifier, separating solid from water. When the solids collection time is over, the lockhopper is isolated from the radiant cooler sump and depressured. After that, the solids are water flushed into the slag dewatering bins. After a preset time, the water flush is discontinued and the lockhopper is filled with water and repressured. The next collection period begins when the lockhopper inlet valve is opened for a new cycle.

Solids from the lockhopper are dumped onto a concrete pad at the slag dewatering bins. In the bins, the solids settle into a pile and are dewatered by gravity. The slag, after dewatering, is then transported by front-end loaders to trucks for off-site shipment or to the on-site temporary slag storage area. The water removed from the slag is gravity drained via concrete trenches to the slag dewatering sump for recovery.

Again, all waters produced in this slag handling system are collected and routed to the black water handling system for reuse.

This system generates the coarse slag material at a maximum rate of approximately 210 short-tons per day (stpd) on a dry basis. The slag has been classified by EPA as nonhazardous and non-leachable and is marketed for various offsite commercial uses such as abrasives, roof material, industrial filler, concrete aggregate, or road base material.

During periods when the slag by-product cannot be sold in a timely manner, a temporary storage area will be employed on the site. Initially, an area was developed to be capable of storing slag generated by approximately 2-1/2 years of operation of the IGCC unit at full capacity. An additional 2-1/2 year storage area will be developed as needed in the unexpected event that sales of the slag for offsite uses are less than the slag production rates. The temporary slag storage area would provide sufficient capacity for developing storage cells for up to five years of slag production from the IGCC unit operating at 100-percent capacity. The slag storage area includes a stormwater runoff collection basin and surrounding berm to prevent runoff from reentering the area. Both the slag storage area and the runoff collection basin are lined with a synthetic material or other materials with similar low permeability characteristics. The runoff basin is designed to contain runoff water volumes equivalent to 1.5 times the 25-year, 24-hour storm event. Water collected in the runoff basin is routed to the IWT for filtration.

H. SULFURIC ACID PLANT

In the sulfuric acid plant, the sulfur-containing acid gases from the hot and cold gas cleanup systems are converted to 98 percent sulfuric acid for sale to the local Florida fertilizer industry. The conversion of acid gases involves a multi-step combustion, gas cleaning, and catalytic reaction process.

In the HGCU process, an acid gas is produced containing sulfur dioxide (SO_2). In the CGCU process, hydrogen sulfide (H_2S) containing gases from the acid gas removal unit and the ammonia stripping unit is routed through separate knockout drums at the acid plant to remove any entrained water. The CGCU gases are then introduced into the decomposition furnace, along with staged combustion air to limit NO_X formation. Supplemental fuel is not normally required; but may be added to maintain the proper operating temperature during periods of low H_2S feed gas concentration. Hot gases from the HGCU unit are introduced into the system downstream of the decomposition furnace and mix with the combusted acid gas from the CGCU unit. The sulfuric acid plant is capable of operating with or without the HGCU feed gas.

The combusted gas stream (containing SO_2, SO_3, water vapor, and trace H_2SO_4) are cooled in a firetube waste heat boiler. The boiler steam side is maintained above 400 psig to avoid condensing acid in the tubes. The gases from the waste heat boiler are cooled in a DynaWave gas cleaning system via a circulating stream of weak acid. The DynaWave system consists of a gas quenching section with the hot process gas forced down through a countercurrent spray of weak acid, followed by a conventional packed gas cooling tower. Water condensed from the process gas absorbs some of the SO_3 in the process gas, thus creating the circulating weak acid stream. An effluent stream of weak acid is removed from the plant to enable the manufacture of 98 percent product acid.

Reaction air in the form of low-pressure 95-percent purity oxygen is added to the process gas stream downstream of the DynaWave system to provide the required amount of oxygen for the SO_2 to SO_3 conversion in the acid plant's catalytic converter.

The gases leaving the DynaWave system flow to a drying tower, where the remaining water vapor and SO_3 are removed by countercurrent washing with 96 percent acid. It is essential (for corrosion concerns) that these components be removed from the process gas stream prior to the catalytic conversion step. The gases from the drying tower pass through candle-type mist eliminators and go to the main blower which provides the necessary pressure for flow through the converter beds and remaining absorber towers.

The gases from the blower are then heated in the converter gas - gas exchangers to achieve the proper reaction temperature and sent through catalytic converter beds. The converter contains three catalyst beds charged with vanadium pentoxide catalyst. The gas-gas heat exchangers transfer heat generated in the SO_2 to SO_3 conversion to the process gas entering each catalyst pass, maintaining reaction threshold temperature. After the first two beds, the process gas is passed through an intermediate absorption tower, where SO_3 is absorbed by circulating 98 percent acid. After the third bed, the process gas is passed through a final absorption tower where SO_3 is again removed by countercurrent 98-percent acid absorption, and subsequently the stripped process gas is low enough in SO_2 content to release to the atmosphere. Mist eliminators at the top of each absorber tower mitigate the carryover of acid mist.

The H_2SO_4 unit is located northeast of the gasification facilities on the site. The facilities include an aboveground tank to provide for five days of temporary storage of the 98-percent H_2SO_4 saleable by-product and a loading rack that can accommodate either DOT-standard rail cars or tank trucks.

Stormwater runoff from the H_2SO_4 storage, handling, and loading area is directed to the Industrial Wastewater Treatment (IWT) system for appropriate treatment prior to being routed to the cooling reservoir for reuse. Acid spills from the storage, handling, and loading areas are contained and either routed to rail cars/tank trucks for sale or to the HRSG blowdown sump, depending upon the acid concentration.

I. BALANCE OF PLANT SYSTEMS

1. Cooling Water

The steam electric generating components of the IGCC unit require water to cool or condense the exhaust steam from the steam turbine. Cooling water is also required for gasification, ASU, sulfuric acid, and other miscellaneous users. The waste heat transferred to the cooling water must then be rejected to the atmosphere. The cooling/heat rejection system for the Polk Power Station is a cooling reservoir.

The cooling reservoir was constructed in areas which have previously been mined for phosphate and consisted of water-filled mine cuts between rows of overburden spoil piles. The reservoir occupies an area of approximately 860 acres, including the areas of the surrounding and internal earthen berms. The reservoir is a primarily below-grade facility after final contouring and development of the site.

Intake and discharge structures to provide and subsequently discharge the cooling water are constructed within the cooling reservoir. The estimated circulating cooling water flow requirements are approximately 130,000 gpm for the steam turbine condenser and 40,000 gpm for the remainder of the plant including the air separation unit. One set of two 50 percent pumps supplies water for the condenser, and another set of two 50 percent pumps supplies water for the other users. The warmed return water is routed throughout the reservoir area by the internal berm system and cooled through evaporation prior to intake and reuse in the system.

For users that require higher quality water than that provided by the cooling reservoir, two closed loop cooling water systems are provided: one for the power generation area and the other for the gasification area. Heat is rejected from these loops to the cooling water from the reservoir.

2. Fuel Oil Storage

The plant has storage for 2,000,000 gallons of No. 2 fuel oil, which is used to fire the auxiliary boiler and the combustion turbine when it is fired with fuel oil.

Fuel oil is unloaded from the tank trucks and pumped by the fuel oil truck unloading pumps to the fuel oil storage tank. From the fuel oil storage tank, the fuel oil is pumped to either the combustion turbine fuel forwarding skid and to the auxiliary boiler.

The unloading area is curbed and the storage tank area is diked. All rainfall and spills in these areas are collected and sent to an oily-water separation system.

SECTION VI

PROJECT MANAGEMENT

VI. PROJECT MANAGEMENT

The management style selected for this project has been one of fully integrated and empowered teams. This is evident from the very inception of the project. When Tampa Electric Company (TEC) assumed the Cooperative Agreement with the U. S. Department of Energy (DOE) for this Demonstration IGCC Project, an important condition was to incorporate the expertise of TECO Power Services, Inc. (TPS) to provide overall project management for the DOE portion of the project. TECO Power Services, Inc. is a TECO Energy, Inc. subsidiary and affiliate of Tampa Electric Company.

Early in the life of the project, Tampa Electric decided to form and periodically convene a panel of experts to guide the design philosophy for the facility. This Technical Advisory Committee (TAC) is comprised of key members of organizations on the leading edge of power system technology and gasification system design and operating experience. Member organizations include Texaco, General Electric Company, Bechtel Power Corporation, the Electric Power Research Institute (EPRI), Southern California Edison Company (Cool Water plant experience), Tennessee Eastman Division of Eastman Chemical Company, TECO Power Services and Tampa Electric Company. This group met three times in 1993, once in 1994, and remains involved on an as-needed basis. The substantial recommendations from this group have contributed to improvements in the areas of plant design, plant layout, equipment selection and configurations, sparing philosophies, safety considerations, reliability analysis, training requirements, start-up sequencing and others too numerous to mention. The TAC has proven to be a valuable asset to the project and we look forward to its continued involvement and contributions. Although no formal group meetings were held in 1995 or 1996, informal discussion among the participants did occur. There will be a final closeout meeting to discuss results of the Polk Power Project among the participants.

When the detailed engineering contract was signed with the project A/E, Tampa Electric and Bechtel created an integrated engineering team within the Bechtel offices in Houston, Texas. This decision was made to utilize the extensive coal-fired power plant experience within Tampa Electric to enhance the design effort of the Houston-based engineering team and to accelerate the decision making process. TEC's Engineering Project Manager and lead discipline-level engineers translocated to Houston to complete this important mission. This working arrangement has been very effective, and a true spirit of teamwork prevailed. Early in 1995 the Engineering team transitioned back to Tampa, Florida to support construction. This lent continuity to project activities from engineering to construction particularly with the ASU, the Sulfuric Acid Plant and the Gasification Plant. Both of the Bechtel contracts were structured heavily with performance incentives. These incentives helped align both companie's interest.

Concurrent with the formation of the integrated engineering team, a similar team of procurement specialists was assembled. TEC team members who translocated to Bechtel's offices in Houston included the Procurement Manager, a Deputy Project Manager, Major Contracts Administrator and several procurement specialists. The integrated TEC-Bechtel procurement, contracts administration and expediting team was, and continues to be, very effective in providing expertise, consistency and timely response for this important function. In early 1995, some members of this team transitioned to the field to provide continuity and assist with material receipt, while other team members completed the required tasks in Houston. By the end of 1995, all procurement activities had been relocated to a site field office.

Another key member of the integrated project team based in Houston was TEC's Construction Manager. In addition to the contract for detailed engineering, Bechtel subsequently competitively bid and was awarded the contract for the project's Construction Management (CM). TEC's CM representative has worked shoulder-to-shoulder with Bechtel's Construction Manager to add TEC-specific construction experience to this effort, and transitioned to the field in July of 1994, and the Bechtel construction manager mobilized in Tampa in January 1995. The Bechtel and Tampa Electric project managers mobilized at the project site in April of 1995. This allowed for close coordination of all project activities from one central location. All of the assigned field personnel were demobilized in 1996.

Since the project's inception, DOE/METC (Morgantown Energy Technology Center) has provided guidance and direction toward key program objectives. DOE's involvement has been a very important part of the project in several ways. The DOE Technical Design Team conducted a "40% complete" review of the engineering progress in early 1994 at the Bechtel offices in Houston, and a "90% complete" design review in early 1995. Quarterly project review meetings were conducted during 1994, 1995 and 1996 and the DOE Technical Design Team continues to monitor progress of the HGCU engineering work as well as of the developmental work at the HGCU pilot plant at G.E.'s Corporate Research and Development (CR&D) Laboratories in Schenectady, N.Y. Close and frequent communication between the TEC and DOE/METC Project Managers provides focus for the project and expedites the in-process adjustments necessary for a project of this type.

Additionally, alignment meetings have been held at various working levels throughout the life of the project, from Senior Management through key discipline-levels. Meetings such as these have helped to bring focus to the critical success factors necessary to make the Polk IGCC Project a technical and commercial success for all project participants, and for the electric utility industry.

Each of the major project participants has been challenged to review their traditional "business as usual" practices, and make internal adjustments at times due to the highly fluid design environment and evolving technologies that comprise this project. Tampa Electric appreciates the flexibility and spirit of teamwork that continues to be displayed by our project partners.

We fully expect the project management style utilized for this project to be an effective model for IGCC projects of the future.

SECTION VII

PROJECT COST