Tampa Electric Integrated Gasification Combined-Cycle Project

Project Completed

Participant

Tampa Electric Company

Additional Team Members

Texaco Development Corporation—gasification technology supplier

General Electric Corporation—combined-cycle technology supplier

Air Products and Chemicals, Inc.—air separation unit supplier

Monsanto Enviro-Chem Systems, Inc.—sulfuric acid plant supplier

TECO Power Services Corporation—project manager and marketer

Bechtel Power Corporation—architect and engineer

Location

Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station (PPS), Unit No. 1)

Technology

Advanced integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, entrained-flow, oxygen-blown gasifier technology

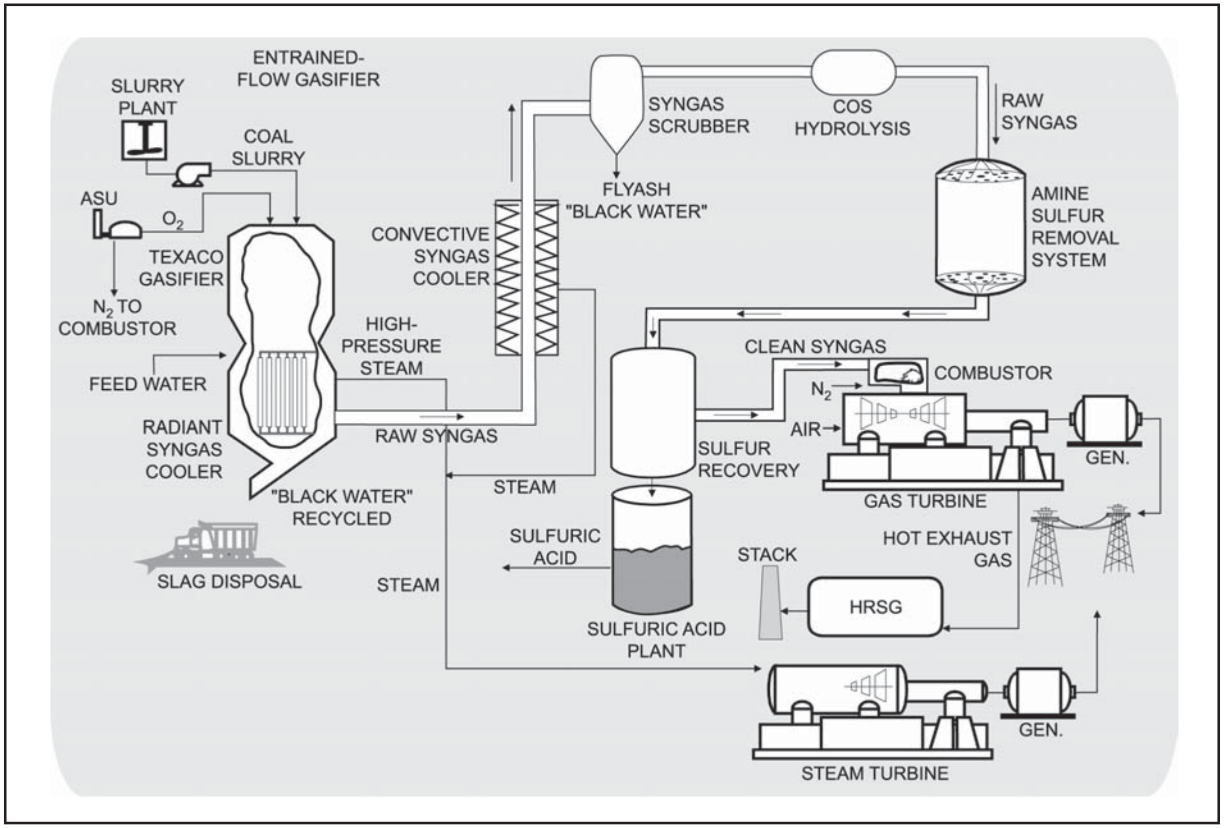
Plant Capacity/Production

315 MWe (gross), 250 MWe (net)

Coal

Illinois #5 & #6, Pittsburgh #8, West Kentucky #11, and Kentucky #9, Indiana #5 & #6 (2.5–3.5% sulfur); petcoke; petcoke/coal blends; and biomass

*Additional project cost overruns were funded 100% by the participant for a final total project funding of $606,916,000.



Project Funding

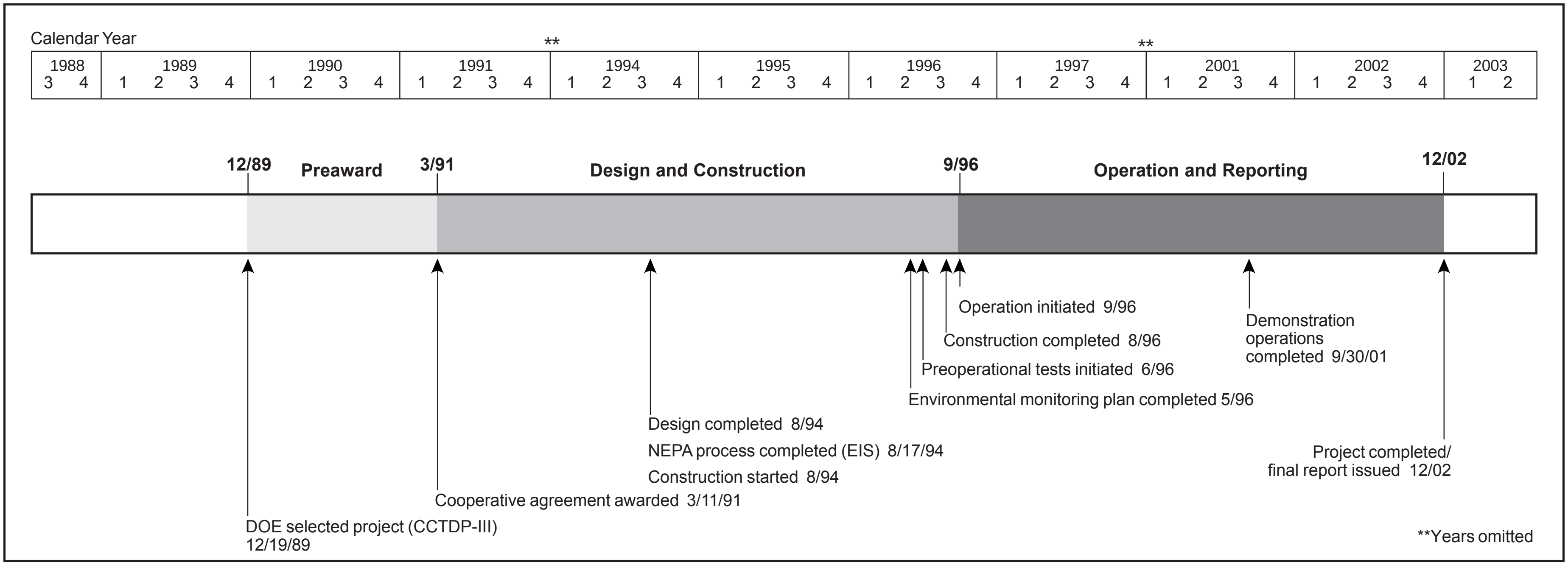
Total*	$303,288,446	100%
DOE	150,894,223	49
Participant	152,394,223	51

Project Objective

To demonstrate IGCC technology in a greenfield commercial electric utility application at the 250-MWe size using a pressurized, entrained-flow, oxygen-blown gasifier with full heat recovery, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control.

Technology/Project Description

Coal/water slurry and oxygen are reacted at high temperature and pressure to produce approximately 245 Btu/SCF syngas (LHV) in a Texaco gasifier. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it forms a solid slag. The syngas moves from the gasifier to a radiant syngas cooler and a convective syngas cooler (CSC), which cool the syngas while generating high-pressure steam. The cooled gases flow to a water-wash syngas scrubber for particulate removal. Next, a hydrolysis reactor converts carbonyl sulfide (COS) in the raw syngas to hydrogen sulfide (H_2S) that is more easily removed. The raw syngas is then further cooled before entering a conventional amine sulfur removal system and sulfuric acid plant (SAP). The cleaned gases are then reheated and routed to a combined-cycle system for power generation. A GE MS 7001FA gas turbine generates 192 MWe. Thermal NO_x is controlled to 0.7 lb/MWh by injecting nitrogen. A steam turbine uses steam produced by cooling the syngas and superheated with the gas turbine exhaust gases in the HRSG to produce an additional 123 MWe. The air separation unit consumes 55 MW and auxiliaries require 10 MW, resulting in 250 MWe net power to the grid. The plant heat rate is 9,650 Btu/kWh (HHV).



Results Summary

Environmental Performance

- The PPS IGCC removed over 97% of feedstock sulfur when operated on low-cost, high-sulfur coal, petcoke, and coal/petcoke blends.
- Typical NO_x emissions were 0.7 lb/MWh, which were below the permitted limit of 0.9 lb/MWh and far below New Source Performance Standard (NSPS) NO_x levels of 1.6 lb/MWh for electric utility units.
- The PM emissions were typically less than 0.04 lb/ MWh, which is about 5% of those from conventional coal-fired plants equipped with electrostatic precipitation.
- The CO emissions were permitted at 99 lb/hr and averaged 7.2 lb/hr; volatile organic compound (VOC) emissions were negligible; and mercury emissions (on coal) without controls were half the potential release based on mercury levels in the coal.

Operational Performance

- The PPS combustion turbine logged 34,800 hours over the 5-year demonstration, of which 28,500 hours were syngas-fired; syngas firing produced over 8.6 million MWh of electricity.
- The gasifier on-stream factor steadily increased, reaching 70–80% after 2½ years; overall PPS availability, with distillate fuel as backup, averaged 90% after 1½ years.
- Carbon conversion was lower than expected—in the low to mid 90% range versus the expected 97.5–98%. This rendered the ASU design capacity inadequate because of a need to recycle flyash, lowering PPS output to 235 MWe net, and required doubling the capacity of the solids handling system.
- Refractory liner life was problematic during the demonstration largely due to frequent fuel changes and attendant undesirable fluctuations in operating conditions, but a coal/petcoke blend was identified to eliminate the problem in commercial service.
- In the high-temperature heat recovery systems downstream of the gasifier, the radiant syngas cooler seals underwent design changes or corrections for fabrication defects; convective syngas coolers required geometric improvements to reduce plugging; and raw gas/clean gas heat exchangers required removal due to stress corrosion.
- A COS hydrolysis unit had to be added to meet sulfur-reduction targets and an ion exchange unit added to prevent buildup of heat-stable salts in the MDEA unit.
- “Y” strainers and a 10 micron filter system proved critical to turbine protection from pipe-scale during start-ups.

Economic Performance

- A capital cost of $1,650/kW (2001$) was estimated for a new 250 MWe (net) IGCC plant based on the PPS configuration incorporating lessons learned. A capital cost of $1,300/kW (2001$) was estimated for a new plant that allowed for benefits derived from economies of scale, technology improvements, and replication of proven configurations to eliminate costly reinvention.

Project Summary

Tampa Electric worked with the local community, state organizations, and environmental groups to make the project an environmental showcase; and engaged DOE and the technical community to move IGCC closer to mainstream market acceptance. Both of these goals were met.

This project has been the recipient of numerous environmental and technological achievement awards. These include the Ecological Society of America Corporate Award, the Florida Audubon Society Corporate Award, and *Power* magazine's 1997 Power Plant of the Year Award. The plant was inducted into *Power* magazine's Power Plant Hall of Fame.

Over the 5-year demonstration period, Tampa Electric carried out a systematic campaign to address and resolve the usual technical issues accompanying first-of-a-kind plants. Tampa Electric showed through the demonstration that a modest-sized utility, with expertise in coal-fired generation, can build and operate an IGCC plant.

Environmental Performance

The PPS IGCC removed over 97% of the feedstock sulfur when operated on low-cost, high-sulfur coals, petcoke, and blends. A material balance on a 3.0% sulfur coal showed that 7.0% of the sulfur is locked up in the inert slag leaving the gasifier. The MDEA acid gas system removed 97.5% of the H_2S from the raw syngas. The COS hydrolysis to H_2S proved critical to maintaining high sulfur capture efficiency because 5% of the sulfur in coal feedstocks was converted to COS (twice the amount expected) and the MDEA system was not effective in removing COS. The SAP recovered 99.7% of the sulfur it was fed.

Permit limits on NO_x emissions during the PPS demonstration period were 25 parts per million by volume on a dry basis (ppmvd) corrected to 15% O_2. This value equated to 35 parts per million (ppm) as measured at the stack by a continuous emissions monitor (CEM). The permit limit is also equivalent to about 220 lb/hr NO_x or 0.9 lb/MWh. Typical Polk IGCC NO_x emissions were about 0.7 lb/MWh, or below 30 ppm by CEM. These emission rates are a fraction of those from conventional coal-fired power plants equipped with low-NO_x combustion systems. For comparison, the NSPS for electric utility units is 1.6 lb/MWh, regardless of fuel type.

The PM emissions from the IGCC are typically less than 0.04 lb/MWh, which is approximately 5% of those from conventional coal-fired plants equipped with electrostatic precipitators. These near-zero emissions are the result of the concentrated, low-volume raw syngas flow and application of intensive liquid scrubbing and no less than 15 stages of liquid-gas contact.

The CO emissions, permitted at 99 lb/hr, averaged 7.2 lb/hr. The VOC emissions, permitted at 3 lb/hr, averaged 0.02 lb/hr. Mercury emissions were not regulated, but measurements taken showed that the IGCC removed about half of the mercury constituent in coal feedstocks.

Operational Performance

Over the course of the demonstration, the PPS combustion turbine logged 34,800 hours of which 28,500 hours were syngas fired. The 28,500 hours of syngas firing produced over 8.6 million MWh of electricity. In producing the syngas, the gasifier typically consumed 2,500 tons of coal or coal/petcoke blends per day.

The gasifier and associated systems involved in producing clean syngas showed steady improvement in the unit's in-service (on-stream) factor over the first four years, reaching 70–80% after 2½ years, before suffering a setback in the fifth and final demonstration year. The fifth year was not considered representative. It included a lengthy planned outage to deal with gasifier refractory damage incurred by frequent feedstock changes, followed by a rare ASU forced outage and the one-time removal of sootblower lances. The on-stream factor is the percentage of time the gasifier and associated systems were in operation over the total number of hours in the year of operation. The availability of the combined-cycle power block to produce electricity from either syngas or distillate was approximately 90% over the last four years of the demonstration. Tampa Electric also calculated on-peak availability because of the importance of the plant in meeting peak summer demand. The peak availabilities for 2000 and 2001 were 94.9% and 97.7%, respectively.

The following is a summary of the highlights of the technical issues that emerged during the demonstration. Most of the issues were resolved, and others served as lessons learned to improve the technology for future plants. Together, the issues served to advance the technology closer to widespread commercial deployment.

Lower-than-anticipated carbon conversion in the gasifier had major cost and performance impacts that reverberated through the IGCC system. Carbon conversions of 97.5–98% per pass were expected based on performance of smaller Texaco gasifiers. The PPS gasifier achieved per pass carbon conversion in the low- to mid- 90% range.

Even at design capacity, the ASU could not deliver enough air to meet the total gasifier oxygen requirements given the unexpectedly low carbon conversion and the resulting need to recycle flyash (which reduced fuel quality). Moreover, Tampa Electric desired the flexibility to process low-quality fuels.

Essentially all carbon steel parts in contact with the slurry feedstock had to be replaced or coated with corrosion-resistant materials, and high-wear areas had to be hardened.

Tampa Electric evaluated numerous modifications to the slurry feed injectors in an attempt to resolve the carbon conversion issue. Only marginal improvement resulted.

A two-year gasifier refractory liner life commercial goal established for the PPS was not met during the demonstration period primarily because of frequent fuel changes. The fuel changes introduced risk in operational settings and less-than-optimal operating conditions as adjustments were made. Also, the high number of start-up and shutdown cycles experienced during the demonstration period accelerated refractory spalling.

Tampa Electric carried out extensive feedstock testing during the demonstration with refractory life being a prime consideration. Testing showed that a blend of 45% Black Beauty and Mina Norte coals with 55% petroleum coke provided excellent cost and performance characteristics and the potential for long refractory liner life.

Contributing to the refractory degradation was the inability to directly measure gasifier temperatures on a realtime basis. Thermocouples failed to survive the gasifier flow path. Gasifier temperature measurements primarily relied on "inferential measurement" based on methane formation. Monitoring and control of gasifier temperature also is critical for control of slag viscosity and flyash volume.

All radiant syngas cooler seals eventually failed due to either fabrication defects or design flaws, all of which were corrected. Corrections included removal of all but 8 of the 122 sootblower lances. Only four lances are used as sootblowers. The other four serve as purge points for injection of N_2 during start-up and shutdown.

The CSC fire-tube heat exchanger was a source of frequent plugging and forced outages through 1999. The plugging primarily occurred at the CSC tubesheet inlet. In 1999, significant geometric improvements dramatically reduced plugging by more than half. Although not eliminated, CSC pluggage is deemed manageable.

The gasifier's lower-than-expected carbon conversion required twice as much fly ash and associated black water to be processed as originally designed. This increased volume essentially overwhelmed the solids handling system, precluded slag sales, and posed significant disposal costs. To resolve these issues, Tampa Electric (1) doubled the capacity of the fines (predominately flyash) handling system; (2) provided the capability to recycle 100% of the settler bottoms flyash to the gasifier slurry preparation system; (3) used condensate water instead of grey water in the slag removal system and stripped the ammonia from that condensate water; and (4) added a drag conveyor and screen to de-water and separate the fly-ash from the slag. With these changes, operation on 100% coal enabled sales of the slag while recycling 100% of the settler bottom flyash and generating 235 MWe (net). Tampa Electric future plans include increasing ASU capacity to provide enough oxygen to compensate for added fuel required to boost output to the rated capacity of 250 MWe year round.

In the original IGCC design, heat exchangers were incorporated downstream of the CSC to recover process heat by warming clean gas and diluent N_2 going to the combustion turbine. Flyash deposits from the raw syngas resulted in stress corrosion, cracking of the tubes, and turbine blade damage. These heat exchangers were removed because the heat recovery, less than 1.7% of the fuel's heating value, did not warrant the cost of redesign.

Tampa Electric incorporated a COS hydrolysis system in August 1999. An ion exchange system was subsequently added to control a high rate of heat-stable salt formation resulting from COS hydrolysis.

The only major power block forced outages during syngas-based operation resulted from failures of the raw gas/clean gas heat exchanger (since removed) in the absence of protective "Y" strainers. The "Y" strainers had been removed for repair. "Y" strainers subsequently proved critical for start-ups because of the release of large volumes of pipe scale. To increase turbine protection and reduce "Y" strainer cleaning, a 10 micron final syngas filter was installed upstream of the syngas strainers. This filter was sized to catch a year's worth of pipe scale.

Economic Performance

Tampa Electric estimated a capital cost of $1,650/kW (2001$) for installing a new single-train 250-MWe unit at the Polk site, based on the PPS configuration and incorporating all lessons learned. This estimate reflected the cost of the plant as if it were instantaneously conceived, permitted, and erected (overnight cost) in mid-2001. The single-train PPS configuration contributed to the high cost in that no benefits accrued from economies of scale in using common balance-of-plant systems. Tampa Electric also noted a number of site-specific factors adding to high costs. Tampa Electric developed another capital cost estimate, that included moderated site-specific factors and allowed benefits from economies of scale, technical improvement, and replication of proven configurations to eliminate costly re-invention. Application of these benefits reduced the estimated capital cost to $1,300/kW (2001$).

Commercial Applications

During the course of the demonstration, Tampa Electric addressed the future of IGCC, reflecting on typical concerns expressed by visitors, numbering over 2,500 and representing 20 countries. In regard to cost, the primary concern, Tampa Electric pointed out that capital costs will be lower for next-generation IGCC, further IGCC demonstrations would accelerate cost reduction, and higher initial costs for IGCC can be offset by long-term fuel savings. As to the associated factor of economic risk, Tampa Electric observed that (1) assumption of overall plant performance risk by a single entity rather than separate entities for individual process units would reduce the difficulty in obtaining financing; (2) a return to steady economic growth in the United States would encourage potential IGCC users to take a longer-term investment view, and (3) a lasting change in the expected availability or price differential of natural gas to coal would tip the risk-versus-reward scale toward IGCC. Also, environmental legislation requiring mercury or CO_2 removal would provide an economic advantage to IGCC over conventional coal-fired power generation because these emissions are readily removed from concentrated IGCC gas streams.

As to availability, Tampa Electric noted that: (1) the PPS gasifier availability is lower than can be expected for subsequent IGCC plants incorporating lessons learned; (2) overall PPS availability, including operation on backup fuel, is very high; and (3) the PPS experience showed that availability can be effectively managed.

Contacts

Mark Hornick, (863) 428-5988
General Manager, Polk Power Station
TECO Energy
P.O. Box 111
Tampa, FL 33601-0111
(863) 428-5927 (fax)

Victor K. Der, DOE/HQ, (301) 903-2700
victor.der@hq.doe.gov

Leo E. Makovsky, NETL, (412) 386-5814
leo.makovsky@netl.doe.gov

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