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Project Summary

Shell NO_x/SO_2 Flue Gas Treatment Process: Independent Evaluation

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Nitrogen oxide (NO_x) emissions from stationary sources may be reduced by 80-90 percent by applying selective catalytic reduction (SCR) of NO_x with ammonia. To further develop this technology, EPA sponsored pilot scale tests of two SCR processes treating flue gas slipstreams from coal-fired boilers. One of the processes tested was the Shell Flue Gas Treatment (SFGT) process which also removes SO_2. An independent evaluation of the SFGT pilot plant tests shows that the process can simultaneously reduce NO_x and SO_2 emissions by 90 percent, even though this was not demonstrated during the pilot plant test program. The process design tested appeared well suited to coal-fired application, and the reactor processed flue gas for 2000 hours without any signs of plugging. An energy analysis indicates that the SFGT process energy requirements equal 5 percent of the boiler's capacity. Process costs were estimated based on the pilot plant test results. Estimated capital investment and annual revenue requirements for the SFGT process are \$168/kW and 9.60 mills/kWh, respectively, significantly higher than previous estimates for the process using the same process design.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

Selective catalytic reduction (SCR) of nitrogen oxides (NO_x) with ammonia (NH_3) can reduce NO_x emissions by 80 percent or more. As such, SCR is an effective process for controlling stationary source NO_x emissions. For a utility application of SCR, a catalytic reactor is between the economizer and air preheater sections of the boiler, where the flue gas temperature is 300-400°C (570-750°F), optimum for the catalytic activity. NH_3, injected into the flue gas upstream of the catalyst, reacts with NO_x on the catalyst surface to form elemental nitrogen and water.

Most SCR processes were developed and are being operated commercially in Japan, primarily on gas- and oil-fired sources. However, in the U.S., SCR systems are now being installed on a limited basis. The most notable application is a demonstration system being constructed to treat half of the flue gas from Southern California Edison's 215 MWe Huntington Beach Unit No. 2 (an oil-fired boiler). Operation of this system is expected to establish SCR as a commercially available technology for oil- and gas-fired sources in the U.S.

In Japan, development efforts are currently aimed at applying SCR to coal-fired sources. To date, most of the SCR process vendors in Japan have operated pilot units on slipstreams from coal-fired boilers. In addition, four full-scale SCR systems now treat flue gas from coal-fired boilers; another eight are scheduled to start up in 1982 and 1983. These development efforts are rapidly establishing SCR as commercially available technology for controlling NO_x emissions from coal-fired sources in Japan.

The transfer of SCR technology from Japan to the U.S. for coal-fired applications is a potentially significant problem. Since most coal-fired boilers in the U.S.

operate ESPs downstream of the air preheater, a typical SCR application would expose the catalyst in the reactor to the full particulate concentration from the boiler. Although, in tests in Japan, the catalyst exposed to high particulate concentrations experienced no adverse effects, the differences in the composition of particulates from U.S. and Japanese coals could impact SCR operation.

To further develop SCR technology and to determine how differences between Japanese and U.S. coal/particulate properties impact the performance of SCR processes, EPA has sponsored pilot scale (0.5 MW equivalent) tests of two SCR systems: Hitachi Zosen (HZ) process and the Shell Flue Gas Treatment (SFGT) process; the latter can also remove SO_2 from the flue gas. In both cases, the pilot plants processed a flue gas slipstream from a coal-fired boiler. Contractors responsible for the design and operation of these pilot plants were Chemico Air Pollution Control Corporation (North American licensee for the HZ process) and the Process Division of UOP (licensing agent of the SFGT process). These contractors were also responsible for collecting, evaluating, and reporting the test data.

The primary objectives of the pilot plant test programs sponsored by EPA were: (1) to demonstrate the ability of the processes to achieve a 90 percent reduction in NO_x emissions and, for the SFGT process, a simultaneous 90 percent reduction in SO_2 emissions; and (2) to determine the impacts of catalyst performance which result from processing flue gas from a coal-fired utility boiler.

In conjunction with the pilot plant test program, EPA contracted with Radian Corporation to prepare an independent evaluation of the processes tested based on the pilot plant results. This document summarizes the results of the independent evaluation of the SFGT process. It includes a discussion of the results of tests conducted by both UOP and Radian and the results of Radian's independent evaluation of the SFGT process. A separate report covering the detailed results of the pilot plant test program has been prepared by UOP.

Program Objectives and Approach

The independent evaluation of the SFGT pilot plant test program conducted by Radian Corporation had three major objectives: (1) to provide independent validation of the process measurements made by UOP; (2) to quantify any changes in the emission rates of secondary pollutants across the pilot plant reactor; and (3) to complete a technical and economic evaluation of the SFGT process including identification of areas which require further development or investigation.

To validate the measurements made by UOP, a quality assurance program was implemented. This program used EPA reference methods and other standard measurement techniques to make independent audits of critical process parameters such as flue gas flowrate, and NH_3 injection rate. In conjunction with the quality assurance program, the continuous NO_x and SO_2 monitors were subjected to certification tests designed to determine the monitors' ability to make accurate repeatable measurements. These certification tests included measurement of the continuous monitors' relative accuracy, drift, calibration error, and response time.

Concurrent with the quality assurance program, a stack sampling program was conducted to measure changes in secondary process emissions across the SCR reactor. This approach required simultaneous sampling of the reactor inlet and outlet for the species of interest. The samples were then analyzed, and differences between inlet and outlet concentrations determined.

Based on the results of the quality assurance program, the stack sampling program, and the test data collected by UOP, an evaluation of the SFGT process was completed by Radian. This evaluation consisted of: (1) analyzing and reducing the test data to a form that could be used to predict process performance for a specified set of operating conditions; (2) using the reduced test data and the results of the stack sampling program, completing material and energy balance calculations for a 500 MWe coal-fired application of the SFGT process (the basis for these calculations was identical to that used by TVA in developing cost estimates for the SFGT process, presented in "Preliminary Economic Analysis of NO_x Flue Gas Treatment Processes," EPA-600/7-80-021); (3) using the results of the material and energy balance calculations to develop a modified estimate of total capital investment and annual revenue requirements for a 500 MW coal-fired application of the SFGT process; and (4) reviewing the test data and identifying areas requiring further investigation/quantification.

Results

Several areas which influence the technical and economic feasibility of the SFGT process were examined as part of this study:

- Pilot plant test results.
- Results of Radian's independent tests.
- Results of a 500 MW conceptual design of the SFGT process.
- Material balance calculations for a 500 MW SFGT process application.
- Energy balance calculations for a 500 MW SFGT process application.
- Estimated capital investment and annual revenue requirements for a 500 MW SFGT process application.

Pilot Plant Test Results

The test program at the SFGT pilot plant, initiated in October 1979, was completed in October 1980. During this period, the pilot plant processed a flue gas slipstream from between the economizer and the air preheater of the coal-fired unit No. 2 at Tampa Electric Company's Big Bend Station. Normal flue gas flowrate to the pilot unit was 1600 Nm^3/hr (1000 scfm), and flue gas was processed for about 2000 hours during the program.

The pilot plant test program involved examining three charges of acceptor material (the material which both catalyzes the NO_x reduction reactions and removes SO_2 from the flue gas) under a variety of test conditions, including tests for simultaneous reduction of NO_x and SO_2 emissions and tests for removal of only NO_x or SO_2. In general, these tests were divided into two categories: optimization tests and demonstration (or long-term) tests. The objective of the optimization tests was to identify operating conditions which would reduce both NO_x and SO_2 emissions by 90 percent at a minimum total cost for operating the process. The major objective of the demonstration tests was to document the ability of the process to achieve a 90 percent reduction in NO_x and SO_2 emissions for 90 days.

The objectives of the pilot plant tests conducted by UOP were not met. Under typical operating conditions, SO_2 removal was 90 percent while the NO_x reduction efficiency averaged only about 70 percent. This was due to poorer-than-expected performance of the acceptor. As a result, the pilot plant reactor was undersized for the flue gas composition at the Tampa Electric site. While the overall program objectives were not met, the tests did document the technical feasibility of applying the SFGT process to a coal-fired power plant. The pilot plant operated for about 2000 hours with no signs of plugging in the reactor; soot blowing was not required.

In terms of process performance, the pilot plant tests did not demonstrate simultaneous reduction in NO_x and SO_2 emissions at design operating conditions. However 90 percent NO_x/SO_2 reduction was achieved by using preoxidation and cooling steps which were not in the original process design. Extrapolation of the pilot plant test results indicates that it should be possible for the process to reduce NO_x and SO_2 emissions by 90 percent without preoxidation and cooling. However, this requires a larger reactor and additional acceptor which will significantly impact the estimated costs for the SFGT process. Because of this cost impact and the good performance achieved by using preoxidation and cooling steps, UOP now proposes to use these steps in the commercial design and operation of the SFGT process.

The test program briefly examined the effects of key operating parameters but did not provide a detailed characterization of the effects of various operating parameters on process performance. Two parameters in particular, temperature and flowrate, were shown to affect process performance, yet their effects were not thoroughly documented. Temperature and flowrate are significant parameters since they would be expected to change with swings in boiler load, thus changing NO_x and SO_2 emission reduction efficiencies.

Probably the most important aspect of the SFGT process performance which was documented during the pilot plant tests was the stability of acceptor activity. The tests showed that, when first exposed to flue gas, acceptor activity initially declined, but then remained stable during the 700 hours of operation. This is favorable in terms of applying the process to a coal-fired boiler since, after the initial decline, there was no measurable change in activity. However, note that this does not document acceptor activity over a period equivalent to 1 year of commercial operation. While demonstration of a 1-year acceptor life was not an objective of the test program, a 1-year acceptor life is critical to the economic feasibility of the SFGT process. And, if the acceptor can maintain activity for longer than 1 year, this could result in a significant reduction in process costs.

Overall, the pilot plant test results indicate that applying the SFGT process to a coal-fired boiler is technically feasible. However, these tests did not demonstrate several key factors:

- The ability of the process to simultaneously reduce NO_x and SO_2 emissions by 90 percent under design operating conditions.
- The performance of the process under conditions which simulate reduced boiler loads.
- The stability of the acceptor over a period equivalent to 1 year of commercial operation.

Of these factors, the one most critical to the commercial success of the process is the stability of the acceptor. Although this was not demonstrated, note that no deterioration of acceptor performance was observed during the program and that UOP will guarantee a 1-year acceptor life for a commerical application of the process.

Results of Radian's Independent Tests

The independent evaluation test program by Radian had two primary objectives: to ensure the quality of the data collected at the SFGT pilot plant and to quantify changes in the concentrations of certain pollutants across the SFGT reactor. Data quality was determined by quality assurance (QA) audits and continuous monitor certification tests; changes in pollutant concentrations were determined by a secondary emissions sampling program. Results of each element of the independent evaluation program are summarized below.

Quality Assurance Audits

The QA audits conducted by Radian were designed to ensure the accuracy of the process data required to characterize the operation of the SFGT pilot plant. Radian used reference methods for auditing process operating parameters which were measured on a continuous or routine basis by UOP. One exception was the measurement of NH_3 emissions which were not routinely monitored by UOP, although the original design of the pilot unit included an analyzer intended to determine NH_3 emissions.

Results of the NH_3 emissions sampling are shown in Table 1. Samples were collected during both NO_x/SO_2 and NO_x-only tests. As shown, the samples from the NO_x-only tests indicate relatively high NH_3 emissions, averaging 49 ppm. But the samples from the NO_x/SO_2 tests indicated NH_3 emissions averaging about 15 ppm. At 15 ppm, NH_3 emissions are not expected to result in any significant operational or environmental problems; however, these emissions are not expected to represent a commercial SFGT process designed for 90 percent reduction of NO_x and SO_2. Changes in reactor design required to achieve the 90 percent NO_x/SO_2 reduction can significantly increase NH_3 emissions.

Results of the other QA audits conducted by Radian are summarized in Table 2. As shown, all but the flue gas flowrate measurements were within 10 percent of the values recorded by UOP. In general, the QA audit results indicate that the process data collected by UOP accurately characterize the operation of the SFGT pilot plant. However, the discrepancy in the flowrate measurements indicated that there could be a problem with this measurement technique: the reactor may have been processing flue gas at greater than design flowrates. This question was resolved during subsequent tests in which UOP confirmed the accuracy of their flowrate measurement by an independent test.

Based on the results of the QA audits and subsequent tests by UOP, the major process measurements made by UOP were determined to be accurate within the limits of the techniques employed to make the measurements. This indicates that the data collected by UOP can be used to characterize operation of the process.

Secondary Emissions Sampling

The secondary emissions sampling program was conducted by Radian during

Table 1. *SFGT Pilot Plant NH_3 Emissions*

Mode of Operation	*NO_x in ppm dry*	*NH_3:NO_x*	*NH_3 Emissions ppm dry*
NO_x/SO_2	380	1.17	15
NO_x/SO_2	420	1.21	16
NO_x/SO_2	390	1.31	22
NO_x/SO_2	375	1.25	17
NO_x/SO_2	-	-	16
NO_x/SO_2	-	-	11
NO_x/SO_2	392	1.17	12
NO_x/SO_2	402	1.19	13
NO_x/SO_2	-	-	16
NO_x Only	420	1.18	47
NO_x Only	327	1.21	52
NO_x Only	224	1.38	48

June and July 1980, concurrent with demonstration tests conducted by UOP. The objective was to quantify changes in the emission rates of pollutants other than NO_x and SO_2. For the most part, these tests were conducted during tests in which both NO_x and SO_2 were being removed from the flue gas.

Table 3 summarizes results of the secondary emissions sampling program at the SFGT pilot plant. As shown, concentrations of both hydrogen cyanide (HCN) and nitrosoamines at the reactor outlet were below the detection limits of the analytical techniques employed. For HCN, this detection limit is equivalent to 10 ppbv; and for N-nitrosodimethylamine, 2 ppbv. For both, concentrations are below that which is considered safe for emission sources.

Decreases in both the hydrocarbon and CO concentrations were measured across the reactor. This change is probably due to oxidation of these pollutants in the reactor. Table 3 also shows that a decrease in SO_3 concentration was also measured across the reactor. This decrease is due to removal of SO_3 from the flue gas in the SFGT reactor. The apparent change in particulate concentration is believed to be due to unaccounted-for stratification in the ducts. Note that results for nitrous oxide (N_2O) are not presented, because the analytical technique used to measure N_2O proved unsatisfactory for use in a flue gas stream.

In addition to measuring the concentration of particulates in the flue gas, an elemental analysis of the particulates was completed in an attempt to determine if erosion of the acceptor has a measurable effect on particulate composition. Table 4 shows results of the elemental analysis of the particulates collected at the SFGT pilot plant. As shown, no significant change in the composition of the particulates was measured with respect to these elements. Changes shown in Table 4 are due to random errors in sampling or analysis and do not represent real changes in particulate composition.

Of the secondary emission sampling results, the most significant was that SO_3 is removed in the SFGT reactor. The removal of SO_3 in the reactor reduces the sulfuric acid dewpoint which permits additional heat recovery in an air preheater downstream of the SFGT process. The additional heat recovery reduces the energy requirements of the process and consequently reduces process costs.

Continuous Monitor Certification Tests

Certification tests were conducted for the SO_2 and NO_x monitors used to measure flue gas concentrations of pollutants at the inlet and outlet of the reactor. The tests were included in the independent evaluation program to ensure the quality of the pilot plant performance data being collected by UOP. Certification of continuous emission monitors (CEMs) involves a formal procedure developed by EPA to ensure the accuracy of monitors measuring emissions from sources which must comply with new source performance standard emission limitations. For a CEM to be certified, it must pass a number of performance tests, including calibration error, response time, drift, and relative accuracy. The performance specifications for each certification test are shown in Table 5, along with test results. The performance specifications are those in the Federal Register, Vol. 44, No. 197,

Table 2. *QA Audit Results*

Measurement Audited	*Audit Procedure*	*Relative[a] Error, %*
Flue Gas Flowrate	*EPA Reference Method 2*	*-14.4*
NH_3 Injection Rate	*Absorption followed by wt gain measurement - (analogous to EPA Method 4)*	*7.6*
Reactor Pressure Drop	*Magnehelic differential pressure gauge*	*-1.4*
Reactor Operating Temperature	*Thermocouple with traverse of reactor inlet*	*-1.3*

[a]*Relative error = $\frac{\text{(Process measurement - Audit result)}}{\text{(Audit result)}} \times 100\%$*

Table 3. *Stack Sampling Results at the SFGT Pilot Plant*

Flue Gas Component	*Reactor Inlet Concentration[a]*	*Reactor Outlet Concentration[a]*	*Measurement Technique*
Nitrosoamines[b]	*<5 µg/dscm[c]*	*<5 µg/dscm*	*Absorption, extraction, gas chromatograph w/nitrogen specific detector*
Hydrogen Cyanide	*<0.01 mg/dscm*	*<0.01 mg/dscm*	*Absorption, distillation, titration*
Sulfur Trioxide	*11.4 ppmv (dry basis)*	*0.1 ppmv (dry basis)*	*Controlled condensation, ion chromatograph*
Hydrocarbons (C_1-C_6)	*28.5 ppmv*	*21.0 ppmv*	*Gas chromatograph flame ionization detector*
Carbon Monoxide	*0.13%*	*<0.017%[b]*	*Fischer gas partitioner*
Nitrous Oxide	-	-	*Infrared spectroscopy*
Particulates	*8.9 g /dscm*	*6.3*	*In-stack filter*

[a]*Average of 2 or more tests.*
[b]*Below the detection limit.*
[c]*dscm = dry standard cubic meter.*

Table 4. Results of Particulate Analysis at the SFGT Pilot Plant[a]

Component	*In*	*Out*	*Out/In*
Al	*8.6%*	*8.0%*	*0.93*
Ca	*1.8%*	*1.8%*	*1.00*
Fe	*12%*	*11.1%*	*0.93*
K	*1.5%*	*1.4%*	*0.93*
Mg	*5100 ppm*	*5000 ppm*	*0.98*
Mn	*300 ppm*	*320 ppm*	*1.07*
Sn	*270 ppm*	*270 ppm*	*1.00*
Na	*4300 ppm*	*5100 ppm*	*1.19*
Si	*20%*	*16%*	*0.80*
Zn	*410 ppm*	*720 ppm*	*1.76*
Cu	*96 ppm*	*100 ppm*	*1.04*
Ti	*5400 ppm*	*5100 ppm*	*0.94*
V	*255 ppm*	*340 ppm*	*1.33*

[a]Concentrations are on a mass fraction basis.

Wednesday, October 10, 1979 - "Proposed Rules: Standards of Performance for New Stationary Sources; Continuous Monitoring Performance Specifications."

As shown in Table 5, results for both the NO_x and SO_2 CEMs met the performance specifications with one exception: the relative accuracy of the outlet NO_x CEM was over 50 percent (performance specifications require a relative accuracy of 20 percent or less). These data indicate that, except for the outlet NO_x analyzer, the CEMs were accurately measuring flue gas NO_x and SO_2 concentrations.

The poor relative accuracy of the outlet NO_x analyzer shown in Table 5 indicates that the CEM was accurately measuring flue gas NO_x concentrations. However, several factors must be considered when evaluating these test results. First, the absolute error in the Method 7 versus the monitor measurements averaged only 16 ppm. This is a relatively small difference. A second factor, which indicates that the outlet NO_x monitor's performance was within acceptable limits, is that the performance specifications require that relative accuracy be less than or equal to 20 percent or 10 percent of the applicable standard, whichever is greater. Using the NSPS for bituminous-coal-fired sources as a basis, the relative accuracy of the outlet NO_x CEM is approximately 5 percent of the standard which is within acceptable limits.

Overall, certification tests indicate that the NO_x and SO_2 CEMs at the SFGT pilot unit were performing acceptably. Therefore, the data collected during the pilot plant tests by UOP represent the pilot plant's performance. This is partially a result of UOP's extensive monitor maintenance program which was designed to ensure the accuracy and quality of the performance data collected.

Results of a 500 MW Conceptual Design of the SFGT Process

A conceptual design of a 500 MW SFGT process was prepared based on selected pilot plant test results. This conceptual design served as a basis for material and energy balance calculations and for a cost estimate for a 500 MW application of the SFGT process.

Table 6 summarizes results of the conceptual design for a 500 MW application of the SFGT process. As shown, the key design variable levels are presented. The results of this design indicate that it is technically possible to simultaneously reduce NO_x and SO_2 emissions by 90 percent using the SFGT process without using preoxidation and cooling steps. However, the reactor size and the quantity of acceptor required to meet the design NO_x and SO_2 reduction efficiencies are significantly greater than previous estimates (based on the same type of process operation).

To some extent, the increase in the quantity of acceptor is a function of the limitations placed on the conceptual design to reflect pilot plant operation. Data were collected which indicate that substantial improvement in NO_x and SO_2 reduction efficiencies could be achieved through modification of process operation. But, limitations of the pilot plant prevented adequate characterization of process performance under modified operating conditions.

Reactor pressure drop and other design parameters are fairly consistent with previous estimates for the processes. The results, however, indicate the need for equipment to control the temperature and flowrate of the flue gas entering the reactor. This is primarily due to the fact that the SO_2 reaction rate is reduced at reduced temperatures and flowrates, and data were not developed to characterize overall process performance under conditions which simulated reduced boiler loads.

In summary, the conceptual design indicates that the SFGT process can simultaneously reduce NO_x and SO_2 emissions by 90 percent. However, this level of emissions reduction is achieved only at the expense of an increased quantity of acceptor and a corresponding increase in costs. Note that there may be other means of improving process performance; but these were not considered in preparing the conceptual design.

Material Balance Calculations for a 500 MW SFGT Process Application

Material balance calculations for a 500 MW application of the SFGT process were included as part of this study to identify raw material requirements for the process and to serve as a basis for an estimate of capital investment and annual revenue

Table 5. Results of the Continuous Monitor Certification Tests at the SFGT Pilot Plant

Certification Test	*Performance Specification*	*Inlet SO_2[a] Monitor*	*Outlet SO_2[a] Monitor*	*Inlet NO_x Monitor*	*Outlet NO_x Monitor*
Calibration Error, %					
-high level	*≤5*	*1.4*	*1.4*	*3.85*	*2.52*
-mid level	*≤5*	*0.7*	*0.7*	*4.62*	*2.62*
Response Time, min	*≤15*	*0.8*	*1.3*	*1.7*	*0.8*
Zero Drift, % (2-hour)	*≤2*	*0.25*	*0.25*	*0.64*	*1.04*
Calibration Drift, % (2-hour)	*≤2*	*0.49*	*0.49*	*1.35*	*1.18*
Relative Accuracy, %	*≤20[b]*	*14.0*	*8.6*	*12.6*	*52.3*

[a]One instrument was used to measure both inlet and outlet of the reactor.
[b]Alternatively, ≤10 percent of the applicable emissions standard.

requirements. The material balance was based on the pilot plant and secondary emissions sampling test results, and thus reflects those results in the estimated process and component flows. The most significant results of the material balance calculations include estimation of hydrogen, steam and NH_3 requirements and NH_3 and SO_2 emissions from the process.

Table 7 summarizes the material balance calculations and compares them with the material requirements identified in TVA's preliminary economic analysis. As shown, hydrogen requirements increase by approximately 25 percent, because H_2 consumption in the pilot plant was higher than previous estimates indicated. Steam requirements increased by the same fraction, indicating that the steam to H_2 ratio of the TVA design is essentially identical to that of the pilot plant tests. The naphtha requirements increase in direct proportion to the hydrogen requirements. This is perhaps the single most important increase in a material flowrate because it has significant impact on annual revenue requirements for the process. The significantly increased NH_3 requirements, due to the high NH_3/NO_x ratio used in preparing the conceptual design, reflect the relatively poor performance of the pilot plant at lower NH_3/NO_x injection ratios. Finally, the quantity of sulfuric acid is essentially unchanged: the same quantity of SO_2 is being removed from the flue gas.

Energy Balance Calculations for a 500 MW SFGT Process Application

An energy balance, completed as part of the evaluation of the SFGT process, defined overall process energy requirements and quantified the heat credits associated with the process. The analysis of energy requirements indicated that the SFGT process has a net energy consumption equivalent to 5 percent of the energy input to the boiler.

Individual components of the overall process energy requirements are summarized in Table 8. As shown, the single largest component of the overall energy requirement is the fuel energy which could be obtained through combustion of the naphtha used to generate hydrogen. This represents over 5 percent of the equivalent energy consumed by the boiler and directly depends on the H_2 requirements of the process. Because the fuel energy requirement is so large, a given percentage decrease in H_2 requirements would result in approximately an equivalent percentage decrease in overall energy requirements for the process. This is a strong basis for further examination of H_2 requirements and the factors which affect H_2 consumption.

The energy requirements associated with steam and electrical energy are less than 50 percent of the fuel energy requirements. For steam, this represents a small fraction of the overall energy requirements of the process and, although some reduction in steam consumption may be possible, it will not significantly influence the annual revenue requirements. In the case of electrical energy, the major portion of this requirement results from the energy of fan compression. This can be reduced by reducing acceptor volume.

The heat credits associated with the SFGT process were estimated to be equivalent to over 3 percent of the energy input to the boiler, and result in nearly a 40 percent decline in the overall energy requirements for the process. The heat credit analysis indicated that nearly all of the potential heat credits can be recovered in a commercial application of the SFGT process.

Estimated Capital Investment and Annual Revenue Requirements for a 500 MW SFGT Process Application

Total capital investment and annual revenue requirements for a 500 MW application of the SFGT process were estimated as part of this evaluation. The estimated costs reflect the results of the pilot plant tests. When compared with the previous estimate prepared by TVA, the modified cost estimates indicate the magnitude of the impact the pilot plant results had on estimated process costs. In addition, comparison of the modified cost estimate with cost estimates for other SCR processes indicates the cost effectiveness of the SFGT process as tested in the pilot plant program.

Table 6. Results of the SFGT Conceptual Design

Parameter	Design Level Developed in this Study
Acceptance Time, min	148
Reactor Depth, m	9
Inlet SO_2 Concentration, ppm	2548
Recycle Rate, %	1.8
NH_3/NO_x Injection Ratio	1.5
Overall NO_x/SO_2 Reduction, %	90
NO_x/SO_2 Reduction Across Reactor, %	89.8
Number of Reactors	8
Cross-sectional Area of each Reactor, m^2	40.75
SFGT System Pressure Drop, kPa	3.93

Table 7. A Comparison of Material Flows for a 500 MW Coal-fired Application of the SFGT Process

Material Requirement	Estimated Flowrate TVA[a]	Estimated Flowrate Radian[b]	Ratio
Steam, kg/hr	31,940	40,300	1.26
Hydrogen, kg/hr	1,300	1,630	1.25
Naphtha, m^3/hr	57	71	1.25
NH_3, kg/hr	830	1,120	1.35
H_2SO_4 from acid plant, kg/hr	16,160	16,160	1.00

[a]Estimated prior to pilot plant test program.
[b]Based on pilot plant test results.

Table 8. Overall Energy Requirement for a 500 MW Application of the SFGT Process

Energy Area	Energy Requirement Gcal/hr	Percent of Boiler Capacity
Heat Credit	(35.75)	(3.2)
Steam	6.98	0.6
Electricity	22.3	2.0
Fuel	63.0	5.6
Total	56.53	5.0

Results of Capital Cost Estimate

Table 9 shows the individual components and the estimated total capital investment for a 500 MW application of the SFGT process. As shown, the total capital investment was estimated to be approximately \$84.2 x 10^6 (equivalent to \$168/kW of generating capacity). Compared to TVA's previous estimate of \$67.2 x 10^6, this represents about a 25 percent increase in total capital investment. The principal difference between the two estimates is the estimated acceptor volume. The required acceptor volume based on the pilot plant tests was estimated to be nearly 90 percent greater, thereby increasing the total capital investment.

Results of the Annual Revenue Requirement Estimate

Table 10 shows the individual components and the total estimated average annual revenue requirements for a 500 MW application of the SFGT process. As shown, the average annual revenue requirement was estimated to be approximately \$33.6 x 10^6 (equivalent to 9.60 mills/kWh). Compared to TVA's previous estimate of \$22.5 x 10^6/yr, this represents almost a 50 percent increase in annual revenue requirements for the process.

As with the capital costs, the principal factor which increased the annual revenue requirements is the increased quantity of acceptor required in the reactor. Additional acceptor as a raw material accounts for over 50 percent of the increase in annual revenue requirements. Another significant factor which increased annual revenue requirements is the estimated increase in naphtha required for hydrogen generation: about 12 percent of the increase in annual revenue requirements.

Table 9. *Estimated Capital Investment for a 500 MW Application of the SFGT Process[a]*

	Investment, \$	*% of total direct investment*
Direct Investment[b]		
NH_3 storage and injection	*890,000*	*1.9*
H_2SO_4 plant	*7,172,000*	*15.2*
Reactor section	*27,455,000*	*58.1*
Flow smoothing section	*2,828,000*	*6.0*
Steam Naphtha reformer	*4,698,000*	*9.9*
Gas Handling	*1,546,000*	*3.3*
Sub-total direct investment (DI)	*44,589,000*	*94.4*
Services, utilities (0.06 x DI)	*2,675,000*	*5.6*
Total direct investment (TDI)	*47,264,000*	*100.0*
Indirect Investment		
Engineering design and supervision	*709,000*	*1.5*
Architect and engineering contractor	*177,000*	*0.4*
Construction expense = 0.25 (TDI x $10^{-6})^{0.83}$	*6,135,000*	*13.0*
Contractor fees = 0.096 (TDI x $10^{-6})^{0.76}$	*1,799,000*	*3.8*
Total indirect investment (IDI)	*8,820,000*	*18.7*
Contingency = 0.2 (TDI + IDI)	*11,217,000*	*23.7*
Total fixed investment (TFI)	*67,301,000*	*142.4*
Other Capital Charges		
Allowance for startup and modification = (0.1) (TFI)	*6,730,000*	*14.2*
Interest during construction = (0.12) (TFI)	*8,076,000*	*17.1*
Total depreciable investment	*82,107,000*	*173.7*
Land	*14,000*	*-*
Working Capital	*2,051,000*	*4.4*
Total Capital Investment	*84,172,000*	*178.1*

[a]Basis: 500MW new coal-fired power plant, 3.5% sulfur coal, 90% NO_x removal, 90% SO_2 removal. Midwest plant location. Project beginning mid-1977, ending mid-1980. Average basis for scaling, mid-1979. Investment requirements for fly ash disposal excluded. Construction labor shortages with overtime pay incentive not considered.

[b]Each item of direct investment includes total equipment costs plus installation labor, and material costs for electrical, piping, ductwork, foundations, structural, instrumentation, insulation, and site preparation.

Cost Comparison and Summary

The capital investment and annual revenue requirements of the SFGT process have been estimated based on the results of the test conducted at the EPA sponsored pilot plant in Tampa, FL. These cost estimates indicate that the capital costs and annual revenue requirements are higher than the estimated costs prior to the test program. A more important comparison, however, is the cost of the SFGT process relative to the cost of a conventional, NO_x only SCR process.

Since the same basis was used in preparing the modified SFGT cost estimate as TVA used in preparing preliminary economic estimates for other SCR processes, it is possible to make a direct comparison with TVA's previously published results. Table 11 shows the estimated annual revenue requirements for two pollution control systems which reduce emissions of particulates, NO_x, and SO_2 by 99.5, 90, and 90 percent, respectively. As shown, the pollution control systems employ two SCR processes tested by EPA; one is the SFGT process. The other SCR process is coupled with a flue gas desulfurization system and both processes have ESPs downstream to put the cost estimates on a common basis.

As shown in Table 11, the estimated costs associated with the SFGT processes are 35 percent higher than those of the pollution control system which employs the HZ SCR process. This indicates that the SFGT process, as tested in the pilot plant and presented in the conceptual design, is not competitive with a conventional NO_x-only SCR process for the 500 MW application examined in this study. Note, however, that the relative costs in Table 11 are only valid for one specific application; they could change for other applications.

Overall, the results of the modified cost estimate indicate that, for the particular application examined in this study, the costs of the SFGT process do not appear to be competitive with the costs of other SCR processes, based upon the conceptual design which was limited to operating conditions demonstrated during the pilot plant tests. It is possible that estimated costs would change significantly for a design based on operating conditions which include the use of preoxidation and cooling. It is also possible that SFGT process costs may be more competitive with the costs of other SCR processes for lower sulfur coal applications.

A key factor in all the cost estimates is the useful life of the acceptor. The

Table 10. Estimated Average Annual Revenue Requirements for a 500 MW Application of the SFGT Process[a]

Item	Annual quantity	Unit cost ($)	Annual cost ($)	% of annual revenue required
Direct Costs				
Raw materials				
NH_3	7.87 x 10^6kg	0.16512/kg	1,299,500	3.87
Naphtha	39,773 m^3	132.1/m^3	5,254,000	15.65
Catalyst	-	-	12,600,300	37.53
Reformer catalyst	-	-	125,100	0.37
Total raw materials			19,278,900	57.42
Conversion costs				
Operating labor and supervision	29,200 labor hrs	12.50/ labor hr	365,000	1.09
Utilities				
Naphtha	9,943 m^3	132.1/m^3	1,313,500	3.91
Steam	179,900 GJ	1.90/GJ	341,200	1.02
Process water	8,078,000 m^3	0.23/m^3	128,000	0.38
Electricity	68,859,000 kWh	0.029 kWh	1,996,900	5.95
Heat credit	1,047,500 GJ	-1.90/GJ	(1,896,000)	(5.65)
Maintenance			1,891,000	5.63
Analyses	4,380 labor hrs	17.00/labor hr	74,500	0.22
Total conversion costs			4,214,100	12.55
Total direct costs			23,493,000	69.97
Indirect Costs				
Capital charges				
Depreciation = (0.06) (total depreciable investment)			4,926,400	14.67
Average cost of capital = (0.086) (total capital investment)			7,238,800	21.56
Overheads				
Plant = (0.5) (conversion costs minus utilities)			1,165,300	3.47
Administrative = (0.1) (operating labor costs)			36,500	0.11
Marketing = (0.1) (sales revenue)			366,000	1.09
Total indirect costs			13,733,000	40.90
Spent catalyst disposal			11,400	0.03
Gross average annual revenue requirement			37,237,400	110.90
Byproduct Sales Revenue				
H_2SO_4	11.1 x 10^6kg	-0.033/kg	(3,660,000)	(10.90)
Total Annual Revenue Requirements			33,577,400	100.00

[a]Basis: 500 MW new coal-fired power plant, 3.5% S coal. 90 percent NO_x reduction, 90 percent SO_2 removal. Midwest power plant location, 1980 revenue requirements. Remaining life of power plant = 30 years. Plant on line 7000 hr/yr. Plant heat rate equals 9.5 GJ/kWh. Investment and revenue requirement for disposal of fly ash excluded. Total direct investment $47,264,000; total depreciable investment $82,107,000; and total capital investment $84,172,000.

Table 11. Estimated Annual Revenue Requirements for Two Pollution Control Systems

	Annual Revenue Requirements, $ x 10^{-6}			
SCR Process	SCR	FGD[a]	ESP[a]	Overall
SFGT	33.6	-	3.0	36.6
Hitachi Zosen	10.2	14.7	2.2	27.1

[a]FGD and ESP costs are from "Preliminary Economic Analysis of NO_x Flue Gas Treatment Processes." Tennessee Valley Authority - Office of Power. EPA-600/7-80-021, February 1980.

estimates presented in this evaluation assumed a 1-year life. If the acceptor life is longer or shorter than 1 year, costs could vary significantly from those estimated in this study. Further development work could focus on defining acceptor life and on demonstrating alternate operating/design conditions designed to minimize acceptor requirements.

Conclusions

The following conclusions are based on work performed during this study. For the most part, the information obtained during the course of the study is summarized in the report and serves as background for these conclusions. The major conclusions of this study are:

- The SFGT process can simultaneously reduce NO_x and SO_2 emissions by 90 percent when applied to a coal-fired boiler. However, this level of emissions reduction can only be attained at the expense of increased acceptor volume (over the pilot plant design) or through the use of operating and/or design options which were tested only for a short time during the pilot plant test program.
- No problems with reactor plugging or declinging acceptor activity were evident during the pilot plant test program. This indicates that the copper oxide acceptor and the parallel passage reactor design appear technically suited for application to a

coal-fired source. The pilot plant tests did not, however, demonstrate a stable acceptor life equivalent to 1-year of commercial operation. While this was not an objective of the test program, it must be verified to establish the technical and economic feasibility of the process.

- The secondary emissions sampling program did not indicate that any adverse environmental impacts would result from application of the SFGT process as operated during the pilot plant tests. However, the measured NH_3 emissions may not be representative of a full-scale application of the process.
- The secondary emissions sampling program established that the SFGT process removes SO_3 from the flue gas. This represents a significant benefit for the process since removal of SO_3 permits recovery of additional heat in the air preheater. In addition, the low concentrations of SO_3 measured at the reactor outlet should preclude any problems with plugging and corrosion of a downstream air preheater due to the formation of ammonium sulfates.
- The conceptual design and material balance calculations indicated that significant increases (over TVA's preliminary estimate) in H_2, steam, and NH_3 consumption are expected based on the pilot plant test results. Of these, H_2 consumption has the greatest impact on the economic feasibility of the process. Since a detailed characterization of the factors which influence H_2 consumption was not completed during the pilot plant tests, it may be possible to reduce H_2 consumption. This area warrants further investigation.
- Nearly all of the potential heat credits available to the SFGT process can be recovered, reducing overall process energy requirements by about 40 percent.
- The overall energy balance indicated that the SFGT process has an energy requirement equivalent to 5 percent of the energy input to the boiler for a 500 MW application. When combined with an ESP, the SFGT process requires about 50 percent more energy than other SCR systems combined with ESPs and FGD systems. The principal component of the overall process energy requirement is the fuel energy associated with the naphtha used to generate hydrogen.
- The estimated total capital investment and average annual revenue requirements for the SFGT process are significantly higher than the costs of a conventional, NO_x-only SCR process combined with an FGD system. This indicates that the SFGT process is not economically competitive with other SCR systems for the case examined as part of this evaluation. However, alternative applications of the SFGT process may be more economically competitive. The alternatives include the use of preoxidation and cooling steps now recommended by UOP and applications of the process on sources firing low-sulfur coal.

Overall, the SFGT process design examined in this study does not appear economically competitive with a conventional, NO_x-only SCR process for high sulfur coal applications. It may be more competitive for low sulfur coal applications, but this evaluation did not quantify costs for such an alternative. In addition, several techniques could reduce overall process costs, but these were not examined in detail during the pilot plant test program.

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The complete report, entitled "Shell NO_x/SO_2 Flue Gas Treatment Process: Independent Evaluation," (Order No. PB 83-144 816; Cost: $23.50, subject to change) will be available only from:
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