STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DEP File No. PSD-FL-194
Polk County

Mr. G. F. Anderson
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601-0111

/

Enclosed is Permit Number PSD-FL-194 to construct a power plant facility at County Road 630 approximately 13 miles southwest of Bartow, Polk County, Florida, issued pursuant to Section (s) 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 2/28/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Cynthia A. Doyle (Clerk) 2/28/94 (Date)

Copies furnished to:
W. Thomas, SWD
D. Martin, Polk Co.
J. Harper, EPA
J. Bunyak, NPS
L. Curtin, Holland & Knight

Final Determination

Tampa Electric Company
Polk County, Florida

260 MW INTEGRATED COAL GASIFICATION
COMBINED CYCLE UNIT

File No: PSD-FL-194
PA-92-32

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

February 17, 1994

Final Determination

The Technical Evaluation and Preliminary Determination for the permits to construct a 260 megawatt (MW) integrated coal gasification combined cycle (IGCC) combustion turbine, coal gasification facilities, an auxiliary boiler and a fuel oil storage tank at an electrical power plant site in Bartow, Polk County, Florida, was distributed on December 20, 1993. The Notice of Intent to Issue was published in the Tampa Tribune on December 27, 1993. Copies of the evaluation were available for public inspection at the Department offices in Tampa and Tallahassee.

No adverse comments on the evaluation and proposed permits were submitted by the National Park Service (NPS) and the U.S. Environmental Protection Agency (EPA) in their letters dated January 27 and January 26, 1994 respectively.

Tampa Electric Company submitted comments on the Technical Evaluation and Preliminary Determination for the Polk Power Station. The applicant noted that the fuel bound nitrogen adjustment should also apply to oil firing during the two year hot gas clean up demonstration period. The Department agrees with the applicant's comment, and includes the language in the permit to reflect that.

The final action of the Department will be to issue the PSD permit (PSD-FL-194) with the changes noted above.

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

Permit Number: PA-92-32
PSD-FL-194
Expiration Date: June 1, 1996
County: Polk
Latitude/Longitude: 27°43'43"N
81°59'23"W
Project: 260 MW Integrated Coal Gasification Combined Cycle Combustion Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and specifically described as follows:

For one 260 MW integrated coal gasification combined cycle (IGCC) combustion turbine (GE 7F CT or equivalent) with maximum heat input at 59°F of 1,755 MMBtu/hr (syngas) and 1765 MMBtu/hr (oil) to be located at the Polk County site near Bowling Green, Florida. The coal gasification facility will consist of coal receiving, storage and process facilities, air separation unit, gasifier, product gas cleaning facilities, acid gas removal unit, and auxiliary equipment. The first phase will also include a 49.5 MMBtu/hr auxiliary boiler and a 71,450 barrel fuel oil storage tank.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Tampa Electric Company (TECO) application received July 30, 1992.
2. Department's letter dated September 22, 1992.
3. TECO's letter dated April 12, 1993.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. A description of and cause of non-compliance; and

b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

GENERAL CONDITIONS:

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(X) Determination of Best Available Control Technology (BACT)
(X) Determination of Prevention of Significant Deterioration (PSD)
(X) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

GENERAL CONDITIONS:

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

A. Operation and Construction

The construction and operation of Polk Power Station (Project) shall be in accordance with all applicable provisions of Chapter 17, F.A.C. The following emission limitations reflect final BACT determinations for Phase I (integrated gasification, combined cycle (IGCC) combustion turbine and auxiliary equipment) of the project fired with syngas or fuel oil. BACT determinations for the remaining phases will be made upon review of supplemental applications. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

B. Heat Input

The maximum heat input to the IGCC combustion turbine (CT) shall neither exceed 1,755 MMBtu/hr while firing syngas, nor 1765 MMBtu/hr while firing No. 2 fuel oil at an ambient temperature of 59° F. Heat input may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the heat input correction to other temperatures shall be provided to DEP for review 120 days after the siting board approval of the site certification. Subject to approval by the Department, the manufacturer's curve may be used to establish heat input rates over a range of temperature for the purpose of compliance determination.

SPECIFIC CONDITIONS:

C. Hours of Operation

The IGCC unit in Phase I may operate continuously, i.e., 8,760 hrs/year.

D. Fuel

Only syngas and low sulfur fuel oil shall be fired in the IGCC combustion turbine. Only low sulfur fuel oil shall be fired in the auxiliary boiler. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent, by weight.

E. Auxiliary Boiler

The maximum heat input to the auxiliary boiler shall not exceed 49.5 MMBtu/hr when firing No. 2 fuel oil with 0.05 percent maximum sulfur content (by weight). All fuel consumption must be continuously measured and recorded for the auxiliary boiler.

F. Fuel Consumption

The maximum coal input to the coal gasification plant shall not exceed 2,325 tons per day, on a dry basis.

G. Fugitive Dust

Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas. Particulate emissions from the coal handling shall be controlled by enclosing all conveyors and conveyor transfer points (except those directly associated with the coal stacker/reclaimer for which an enclosure is operationally infeasible). Fugitive emissions shall be tested as specified in Specific Condition No. J. Inactive coal storage piles shall be shaped, compacted, and oriented to minimize wind erosion. Water sprays or chemical wetting agents and stabilizers shall be applied to uncovered storage piles, roads, handling equipment, etc. during dry periods and, as necessary, to all facilities to maintain an opacity of less than or equal to five percent. When adding, moving or removing coal from the coal pile, an opacity of 20 percent is allowed.

SPECIFIC CONDITIONS:

H. Emission Limits

1. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following:

POLLUTANT	FUEL	BASIS[a]	EMISSIONS LIMITATIONS - 7F CT Post Demonstration Period LB/HR*	TPY[b]
NOx	Oil	42 ppmvd**	311	N/A
	Syngas	25 ppmvd	222.5	1,044
VOC[c]	Oil	0.028 lb/MMBtu	32	N/A
	Syngas	0.0017 lb/MMBtu	3	38.5
CO	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1
PM/PM_{10}[d]	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067
SO_2	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7

Visible Emissions Syngas 10 percent opacity
Oil 20 percent opacity

(*) Emission limitations in lbs/hr are 30-day rolling averages. "Pollutant emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for the emission rate correction to other temperatures at different loads shall be provided to DEP for review 120 days after the siting board approval of the site certification. Subject to approval by the Department, the manufacturer's curve may be used to establish pollutant emission rates over a range of temperature for the purpose of compliance determination."

(**) The emission limit for NO_x is adjusted as follows for higher fuel bound nitrogen contents up to a maximum of 0.030 percent by weight:

SPECIFIC CONDITIONS:

FUEL BOUND NITROGEN (% by weight)	NO_X EMISSION LEVELS (ppmvd @ 15% O_2)
0.015 or less	42
0.020	44
0.025	46
0.030	48

using the formula STD = 0.0042 + F where:

STD = allowable NO_X emissions (% by volume at 15% O_2 and on a dry basis).

F = NO_X emission allowance for FBN defined by the following table:

FUEL BOUND NITROGEN (% by weight)	F (NO_X % BY VOLUME)
0 < N < 0.015	0
0.015 < N < 0.03	0.04 (N-0.015)

N = nitrogen content of the fuel (% by weight).

NO_X emissions are preliminary for the fuel oil specified in Specific Condition D of Conditions of Certification. The permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the Southwest District office in Tampa. The % FBN (Z) following each delivery of fuel shall be determined by the following equation:

$x(Y) + m(n) = (x+m)(Z)$

where x = amount fuel in storage tank
y = % FBN in storage tank
m = amount fuel added
n = % FBN of fuel added
Z = % FBN of composite

(a) Syngas lb/MMBtu values based on heat input (HHV) to coal gasifier and includes emissions from H_2SO_4 plant thermal oxidizer. Pollutant concentrations in ppmvd are corrected to 15% oxygen.

(b) Annual emission limits (TPY) based on 10 percent annual capacity factor firing fuel oil.

$\frac{\text{Load (\%)}}{100} \times$ hours of operation ≤ 876 for fuel oil.

SPECIFIC CONDITIONS:

(c) Exclusive of background concentrations.

(d) Excluding sulfuric acid mist.

2. The maximum allowable emissions from the IGCC combustion turbine, when firing syngas and No. 2 fuel oil **during the two year demonstration period**, shall not exceed the following:

		EMISSIONS LIMITATIONS 7FCT	
POLLUTANT	FUEL	LB/HR*	TPY[a]
NO_x	Oil**	311	N/A
	Syngas	664.2	2,908.3
VOC[b]	Oil	32	N/A
	Syngas	3	38.5
CO	Oil	99	N/A
	Syngas	99	430.1
PM/PM_{10}[c]	Oil	17	N/A
	Syngas	17	74.5
Pb	Oil	0.101	N/A
	Syngas	0.023	0.13
SO_2	Oil	92.2	N/A
	Syngas	518	2,269
Visible Emissions		Syngas 10 percent opacity Oil 20 percent opacity	

(*) Emission limitations in lbs/hr are 30-day rolling averages.

(**) Footnote ** as shown in Specific Condition H.1. for fuel bound nitrogen adjustment also applies to oil firing during the Demonstration Period.

(a) Annual emission limits (TPY) based on 10-percent annual capacity factor firing No. 2 fuel oil.

$$\frac{\text{Load (\%)}}{100} \times \text{hours of operation} \leq 876 \text{ for oil.}$$

(b) Exclusive of background concentrations.

(c) Excluding sulfuric acid mist.

SPECIFIC CONDITIONS:

3. The following allowable turbine emissions, were determined by BACT, and are also tabulated for PSD and inventory purposes:

ALLOWABLE EMISSIONS

POLLUTANT	FUEL	IGCC POST DEMONSTRATION LB/HR	IGCC POST DEMONSTRATION TPY[a]	IGCC 2-YEAR DEMONSTRATION LB/HR	IGCC 2-YEAR DEMONSTRATION TPY[b]
Sulfuric Acid[c]	Syngas	55	241	55	241
Inorganic Arsenic	Syngas	0.0006	0.019	0.08	0.35
Beryllium	Syngas	0.0001	0.0029	0.0001	0.0029
Mercury	Syngas	0.0034	0.017	0.025	0.11

(a) Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(b) Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

(c) Sulfuric acid mist emissions assume a maximum of 0.05 percent sulfur in the fuel oil.

4. Excess emissions from the turbine resulting from startup, shutdown, malfunction, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the Department along with the initial compliance test data. The document may be updated as needed with all updates submitted to the Department within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

5. After the demonstration period, permittee shall operate the combustion turbine to achieve the lowest possible NO_x emission limit but shall not exceed 25 ppmvd corrected to 15% oxygen and ISO conditions.

SPECIFIC CONDITIONS:

6. The combustion turbine will be operated for 12-18 months after the demonstration period (estimated to be from Mid 1998 until December 31, 1999). During that period NO_X emission testing will be performed on the turbine at a regular interval of every 2 months. The Department shall be provided with a test protocol including a time schedule 15 days prior to the initial test. The permittee will provide the Department the emission test results 30 days after the test is performed. These results are not for compliance purposes. The Department shall be notified and the reasons provided if a scheduled test is delayed or canceled.

7. One month after the test period ends (estimated to be by February 2000), the permittee will submit to the Department a NO_X recommended BACT Determination as if it were a new source using the data gathered on this facility, other similar facilities and the manufacturer's research. The Department will make a determination on the BACT for NO_X only and adjust the NO_X emission limits accordingly.

I. Auxiliary Boiler Operation

Operation of the auxiliary boiler shall be limited to a maximum of 1,000 hours per year and only during periods of startup and shutdown of the IGCC unit, or when steam from the IGCC unit's heat recovery steam generator is unavailable. The following emission limitations shall apply:

1. NO_X emissions shall not exceed 0.16 lbs/MMBtu for oil firing.

2. Sulfur dioxide emissions shall be limited by firing low sulfur fuel oil with a maximum sulfur content of 0.05 percent by weight.

3. Visible emissions shall not exceed 20 percent opacity (except for one six-minute period per hour during which opacity shall not exceed 27 percent), while burning low sulfur fuel oil.

J. Performance Testing

Initial (I) compliance tests shall be performed on the turbine using both fuels and on the auxiliary boiler using fuel oil. The stack test for the turbine and the auxiliary boiler shall be performed with the sources operating at capacity (maximum heat rate input for the tested operating temperature). Capacity is defined as 90 - 100 percent of permitted capacity. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for purposes of

SPECIFIC CONDITIONS:

additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department. Annual (A) compliance tests shall be performed on the turbine and the auxiliary boiler with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests for the applicable emission limitations shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 17-297, F.A.C., and the requirements of 40 CFR 75:

1. Combustion Turbine

   a. Reference Method 5B for PM (I, A, for oil only).

   b. Reference Method 8 for sulfuric acid mist (I, for oil only).

   c. Reference Method 9 for VE (I, A).

   d. Reference Method 10 for CO (I, A).

   e. Reference Method 20 for NO_X (I, A).

   f. Reference Method 18 for VOC (I, A).

   g. Trace elements of Lead (Pb), Beryllium (Be) and Arsenic (As) shall be tested (I, for oil only) using Emission Measurement Technical Information Center (EMTIC) Interim Test Methods. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

   h. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A).

   i. ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 for sulfur content of natural gas (I, and A if deemed necessary by DEP).

   j. Reference Method 22 for fugitive emissions (I,A).

2. Auxiliary Boiler

   a. Reference Method 9 of VE (I,A).

   b. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I,A).

SPECIFIC CONDITIONS:

c. Reference Methods 7, 7A, 7C, 7D, or 7E for NO_x (I,A).

Other DEP approved methods may be used for compliance testing after prior departmental approval.

K. Sulfur Content of Fuel

The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 by testing for sulfur content of the fuel oil in the storage tanks once per day when firing oil. Testing for fuel oil heating value, shall also be conducted on the same schedule.

L. Monitoring Requirements

A continuous emission monitoring system (CEMS) shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for the combined cycle unit to monitor nitrogen oxides and a diluent gas (CO_2 or O_2). The applicant shall request that this condition of certification be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the state.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B.

2. CEMS data shall be recorded and reported in accordance with Chapter 17-297.500, F.A.C., 40 CFR 60 and 40 CFR 75. The record shall include periods of startup, shutdown, and malfunction.

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Specific Condition No. H.4. herein, which exceeds the applicable emission limits in Condition No. H.1.

SPECIFIC CONDITIONS:

M. Notification, Reporting and Recordkeeping

To determine compliance with the syngas and fuel oil firing heat input limitation, the permittee shall maintain daily records of syngas and fuel oil consumption for the turbine and the heating value for each fuel. All records shall be maintained for a minimum of two years after the date of each record and shall be made available to representatives of the Department upon request.

N. Applicable Requirements

The project shall comply with all the applicable requirements of Chapters 17-209 through 17-297, F.A.C., and 40 CFR 60 Subparts A and GG. The requirements shall include:

1. 40 CFR 60.7(a)(1) - By postmarking or delivering notification of the start of construction no more than 30 days after such date.

2. 40 CFR 60.7(a)(2) - By postmarking or delivering notification of the anticipated date of the initial startup of each turbine and the auxiliary boiler not more than 60 days nor less than 30 days prior to such date.

3. 40 CFR 60.7(a)(3) - By postmarking or delivering notification of the actual startup of each turbine and the auxiliary boiler within 15 days of such date.

4. 40 CFR 60.7(a)(5) - By postmarking or delivering notification of the date for demonstrating the CEMSs performance, no less than 30 days prior to such date.

5. 40 CFR 60.7(a)(6) - By postmarking or delivering notification of the anticipated date for conducting the opacity observations no less than 30 days prior to such date.

6. 40 CFR 60.7(b) - By initiating a recordkeeping system to record the occurrence and duration of any startup, shutdown or malfunction of a turbine and the auxiliary boiler, of the air pollution control equipment, and when the CEMS is inoperable.

7. 40 CFR 60.7(c) - By postmarking or delivering a quarterly excess emissions and monitoring system performance report within 30 days of the end of each calendar quarter. This report shall contain the information specified in 40 CFR 60.7(c) and (d).

8. 40 CFR 60.8(a) - By conducting all performance tests within 60 days after achieving the maximum turbine and boiler firing rates, but not more than 180 days after the initial startup of each turbine and the auxiliary boiler.

SPECIFIC CONDITIONS:

9. 40 CFR 60.8(d) - By postmarking or delivering notification of the date of each performance test required by this permit at least 30 days prior to the test date; and,

10. 17-297.345 - By providing stack sampling facilities for the combustion turbine and the auxiliary boiler.

All notifications and reports required by this specific condition shall be submitted to the Department's Air Program, within the Southwest District office. Performance test results shall be submitted within 45 days of completion of such test.

O. Submission of Reports

The following information shall be submitted to the Department's Bureau of Air Regulation within 12 months of issuance of this permit:

1. Description of the final selection of the turbine and the auxiliary boiler to be installed at the facility. Descriptions shall include the specific make and model numbers, any changes in the proposed method of operation, fuels, emissions or equipment.

2. Description of the CEMS selected. Description shall include the type of sensors, the manufacturer and model number of the equipment.

3. If construction has not commenced within 18 months of issuance of this permit, then the permittee shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced [40 CFR 52.21(r)(2)]. Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

P. Protocols

The following protocols shall be submitted to the Department's Air Program, within the Southwest District office, for approval:

1. CEMS Protocol - Within 60 days of selection of the CEMS, but prior to the initial startup, a CEMS protocol describing the system, its installation, operating and maintenance characteristics and requirements. The Department shall approve the protocol provided that the system and the protocol meet the requirements of 40 CFR 60.13, 60.334, Appendix B and Appendix F. This condition of certification shall be amended to reflect the Federal Acid Rain Program requirements of 40 CFR 75 when those requirements become effective within the State.

SPECIFIC CONDITIONS:

2. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the Department's Air Program, within the Southwest District office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

Q. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

Issued this 24th day
of February, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary

Best Available Control Technology (BACT) Determination
Tampa Electric Company

Polk County
PSD-FL-194
PA-92-32

The applicant is proposing to construct, in phases, a 1,150 MW power plant in Polk County. The proposed facilities will be known as the Tampa Electric Company Polk Power Station. The first phase will consist of an Integrated Coal Gasification Combined Cycle (IGCC) unit with heat recovery steam generator (HRSG) and steam turbine (ST) for a nominal net 260 MW IGCC unit. The coal-fueled advanced CT will be capable of baseload operations (i.e., 100 percent capacity factor) on syngas, while retaining the option to fire fuel oil as backup (maximum 10 percent capacity factor). Units proposed to be added at Polk Power Station include two combined cycle (CC) units totaling 440 MW (nominal) and six simple cycle (SC) CTs totaling 450 MW (nominal). All of these units will be fired with natural gas as the primary fuel and No. 2 fuel oil as backup. The phased schedule for construction and operation of the proposed generating units at the Polk Power Station is presented in Table 1.

Table 1

Proposed Schedule for Construction and Operation of Generating Units for ultimate capacity at the Polk Power Station Site

Activity/Unit	Start Construction	Completion/ In-Service
Advanced CT, CG & HRSG/ST for 260-MW IGCC unit[a]	First Half 1994	July 1995
75-MW CT	April 1998	January 1999
75-MW CT	April 1999	January 2000
HRSG/ST for conversion of two 75-MW CTs for 220-MW CC unit	April 2000	January 2001
75-MW CT	April 2001	January 2002
220-MW CC	April 2001	January 2003
75-MW CT	April 2005	January 2006
75-MW CT	April 2006	January 2007
75-MW CT	April 2007	January 2008
75-MW CT	April 2008	January 2009
75-MW CT	April 2009	January 2010

a - 220 MW when fired on fuel oil and operated in CC mode.

The IGCC unit will be supported in part through funding from the U.S. Department of Energy (DOE) under the Clean Coal Technology Demonstration Program. Under the program, the IGCC unit will be used to demonstrate the integration of coal gasification (CG) and CC technologies and to demonstrate a more efficient method for removal of sulfur from syngas. The new cleanup technology is called hot gas clean up (HGCU). Conventional methods for sulfur removal for IGCC units require that the gas be cooled prior to cleaning, called cold gas cleanup (CGCU), and then reheated. By comparison, the HGCU technology efficiently cleans the gas at high temperatures, thereby increasing the overall plant efficiency. Under the agreement with DOE, Tampa Electric Company will demonstrate the HGCU system for a 2-year period.

The projected maximum tonnage of regulated air pollutants emitted from the proposed facility based on a 100 percent capacity factor and 8,760 hours per year are shown in Table 2. A simplified flow chart for the operation of the IGCC systems at the site is attached (Figures 1 - 3).

Table 2

Projected Maximum Annual Emissions (tpy)
for ultimate site capacity

Pollutant	IGCC[a]	+	CC[b]	+	SC[c]	=	Total	Significance Rate (tpy)
PM (TSP)	399		260		246		905	25
PM (PM_{10})	399		260		246		905	15
SO_2	2469		720		654		3843	40
NO_x	2923		1308		1014		5245	40
CO	453		1092		978		2523	100
VOC	45		180		168		393	40
Pb	0.15		0.28		0.17		0.6	0.6
H_2SO_4	241		80		72		393	7
Fluorides	0.92		0.17		0.10		1.2	3
Hg	0.12		0.21		0.19		0.5	0.1
Be	0.007		0.013		0.008		0.03	0.0004
Total reduced sulfur (including H_2S)	6.2		0		0		6.2	10

Rev. 1
06/18/93

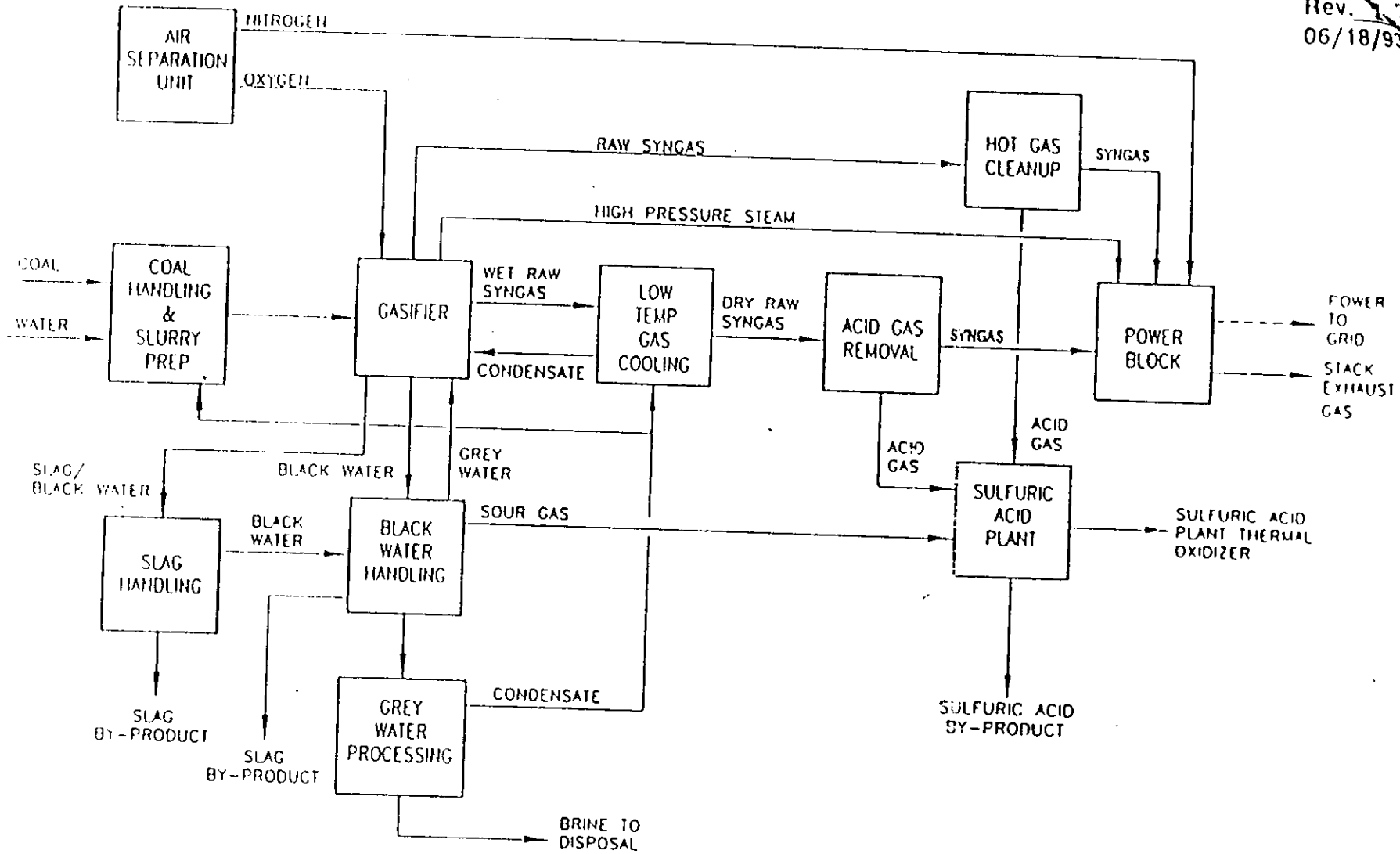

FIGURE 2-2.

GENERALIZED FLOW DIAGRAM OF IGCC SYSTEMS AND PROCESS

Source: ECT, 1993.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

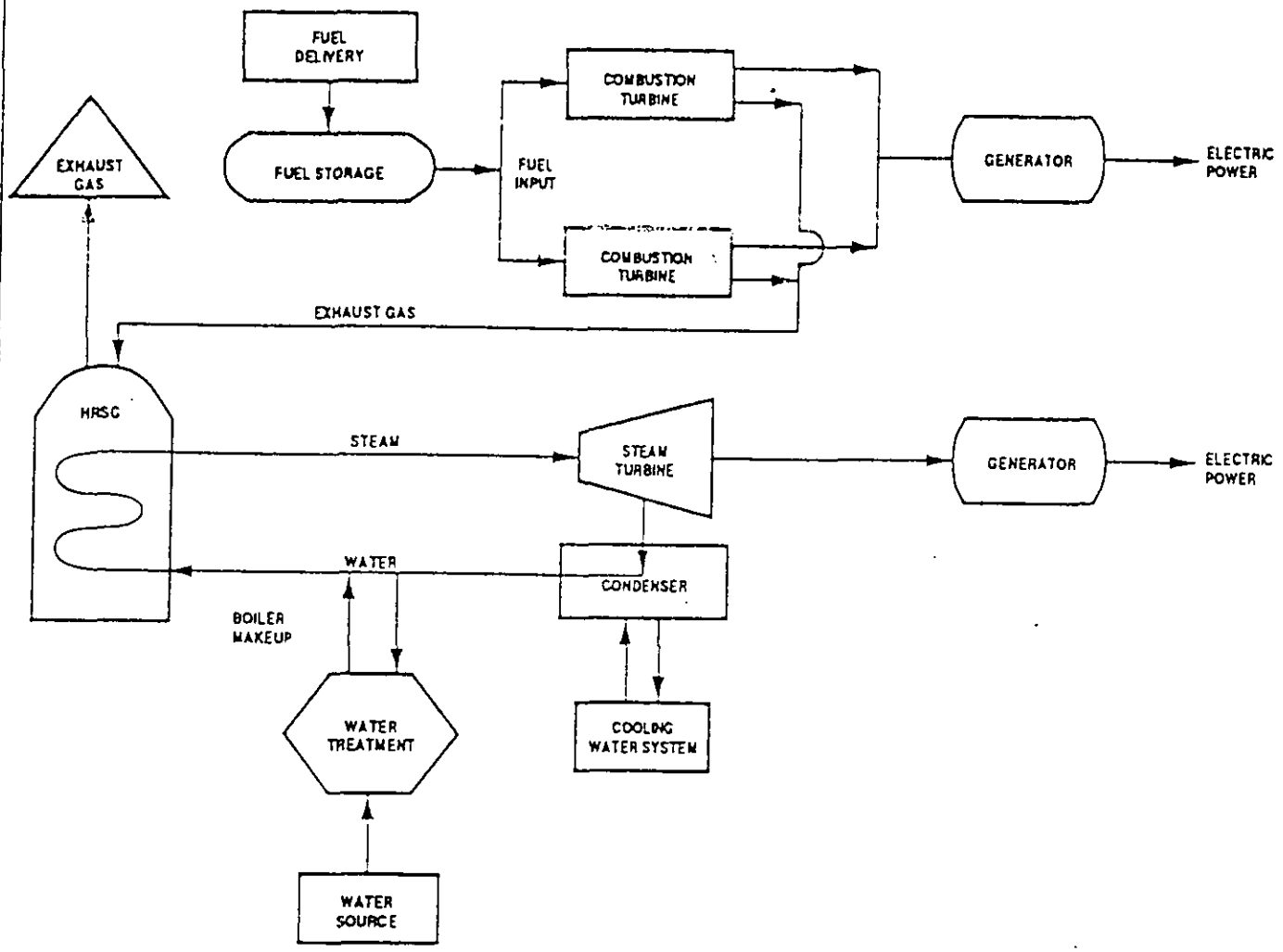

FIGURE 1.5.2-1.

SIMPLIFIED FLOW DIAGRAM OF COMBINED CYCLE POWER SYSTEM

Source: ECT, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

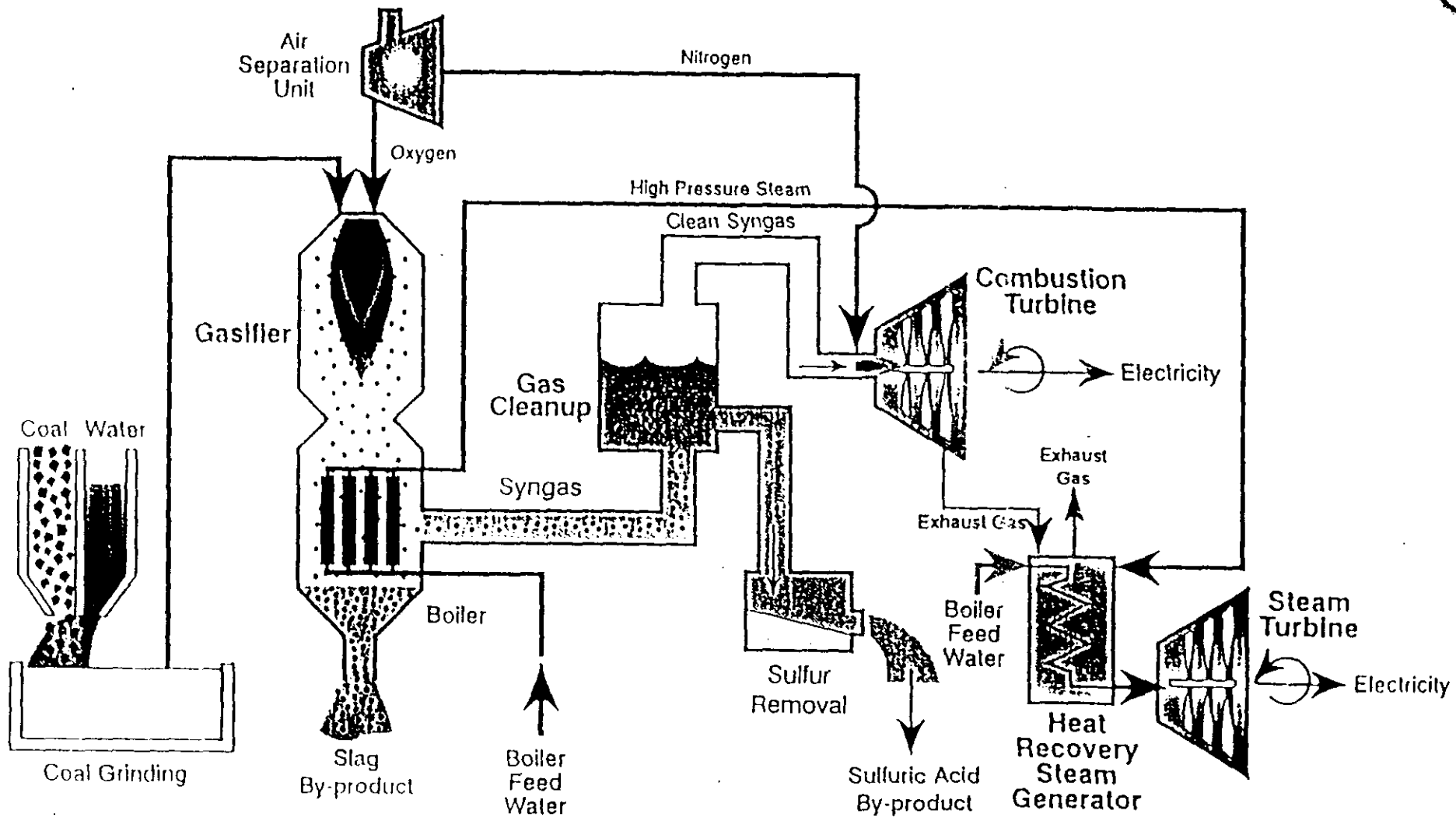

FIGURE 1.5.3-1.

SIMPLIFIED FLOW DIAGRAM OF INTEGRATED COAL GASIFICATION COMBINED CYCLE UNIT

Source: Texaco, 1992. Tampa Electric Company, 1992.

TAMPA ELECTRIC
A TECO ENERGY COMPANY

POLK POWER STATION

a - IGCC emissions include the highest annual emissions estimates from the 7F CT (based on the larger of 100 percent CGCU or 50/50 CGCU/HGCU), plus related combustion emissions (e.g., thermal oxidizer), plus other associated process and fugitive emissions (PM, CO, VOC, and H_2S).

b - CC emissions represent the totals for four stand-alone CTs in CC mode.

c - SC emission represent the totals for six stand-alone CTs in simple cycle mode.

The proposed facility will also include one 49.5 MMBtu/hr auxiliary boiler fired with low sulfur (0.05% or less by weight) distillate fuel oil. The auxiliary boiler will operate only during startup and shutdown of the IGCC unit, or when steam from the IGCC unit's HRSG is unavailable. The auxiliary boiler will operate a maximum of 1,000 hours per year.

The coal gasification facility will serve as a source of medium Btu, low sulfur (0.07% or less, by weight, sulfur bearing compounds) coal-derived gas. The coal used in the gasification facility will have a maximum sulfur content of 3.05% and have a minimum heating value of approximately 11,035 Btu/lb. The coal gasification plant will consist of coal receiving, storage and process facilities, air separation unit, gasifier, product gas cleaning facilities, acid gas removal unit, and auxiliary equipment. The coal gasification unit will have two stacks, one flare stack used during startup, shutdown and emergency conditions and one thermal oxidation unit stack which will be used continuously.

The applicant has indicated the maximum tonnage of regulated air pollutants emitted from the IGCC unit CT during the initial phase, demonstration and post demonstration periods to be as shown in Table 3.

Table 3

Maximum Annual Emissions from IGCC Unit CT for Various Operating Configurations

Pollutant	Demonstration Period (tpy)[a]	Post-Demonstration Period (tpy)[b]
PM[c]	74.5	74.5
SO_2	2,269	1,564
NO_x	2,908	1,044
CO	430	430
VOC	38.5	38.5

H_2SO_4	241	241
Pb	0.13	0.067
Fluorides	0.92	0.92
Hg	0.11	0.017
Be	0.0029	0.0029

a - Based on baseload operations firing syngas, with a maximum of 8,760 hr/yr utilization of HGCU and up to 10 percent annual capacity factor firing fuel oil.

b - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

c - Excluding sulfuric acid mist.

Florida Administrative Code Rule 17-212.400 requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in Table 1.

Date of Receipt of A BACT Application

September 21, 1992

BACT Determination Requested by the Applicant

Combined Cycle Units

Pollutant	Determination
NO_X	9 ppmvd (NG) 25 ppmvd (Syngas firing) 42 ppmvd (No. 2 fuel oil firing)
SO_2	Firing of NG or Syngas Fuel oil with a maximum sulfur content of 0.05 % by weight, 0.048 lb/MMBtu
CO	Combustion control 25 ppmvd (NG) 40 ppmvd (No. 2 fuel oil firing) 25 ppmvd (Syngas firing)
VOC	Combustion control 7 ppmvd (NG) 7 ppmvd (No. 2 fuel oil firing) 1 ppmvd (Syngas firing)

Particulates	Good combustion, and type of fuels fired
Pb	Good combustion, and type of fuels fired
H_2SO_4	Firing of NG, Syngas and No. 2 fuel oil
Be	Firing of NG, Syngas and No. 2 fuel oil
AS	Firing of NG, Syngas and No. 2 fuel oil

Coal Gasification Plant

Raw Product Gas

Pollutant	Control Technology
Sulfur	Acid Gas Removal (95.6%)
Particulates	Water scrubbing

The raw product gas is fired in the combined cycle combustion turbine units and emissions of product gas are included in the BACT determination for those units.

CG Emission (Thermal Oxidizer)

Pollutant	Control Technology
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05% by weight. (45.3 lb/hr)
NO_x	Combustion controls
CO	Combustion controls
Pb	Efficient Operation
H_2SO_4	Efficient Operation
Mercury	Efficient Operation
Beryllium	Efficient Operation
Inorganic Arsenic	Efficient Operation

Materials Handling and Storage

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed - including a Collection System
Conveyers and Transfer Points (Coal, Slag)	Transfer points enclosed with Collection System. Conveyers enclosed
Coal Storage and Reclaiming	Crusting Agent Application Wet Suppression Systems or Crusting Agents Surfactant Application[1]
Fuel Oil Storage	Bottom Loaded/Submerged Filling

Auxiliary Boiler

NO_x	Low NOx Burners and Combustion Controls, limited operation[2] (0.159 lb/MMBtu)
SO_2	Fuel oil firing with a sulfur content not to exceed 0.05 % by weight, and limited operation (0.053 lb/MMBtu)
CO	Combustion Controls (0.087 lb/MMBtu)
VOC	Combustion Controls (0.0485 lb/MMBtu)
Particulates	Combustion Controls (0.061 lb/MMBtu)
Pb	Combustion Controls
Mercury	Combustion Controls
Beryllium	Combustion Controls
Inorganic Arsenic	Combustion Controls

1 - Total Coal Handling Sources PM Emissions are 11.2 tpy
2 - Maximum of 1000 hours of operation per year

Annual pollutant emissions are shown in Table 2 for all sources. Pollutant emission rates are listed in the section entitled "BACT Determination by DEP".

Flare Stacks

This source did not propose a BACT since its operation is expected to be infrequent (startup and shutdown, and emergencies).

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Stationary Sources - Emission Standards, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case-by-case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants and coal fired power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by good combustion of clean fuels and/or fabric filters.
- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.
- Acid Gases (SOx, NOx, HCL, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc.), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

Combustion Products

The IGCC facility's projected emissions for combustion products (Particulate Matter (PM) and trace heavy metals) exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed PM/PM_{10} emission level of 0.013 lbs/MMBtu (excluding H_2SO_4) for syngas for the IGCC unit is consistent with the particulate limit for recent determinations of coal fired boilers. The applicant proposed PM/PM_{10} emission level of 0.009 lbs/MMBtu for No. 2 oil firing for the IGCC unit is consistent with previous BACT determinations in Florida.

In general, the BACT/LAER Clearinghouse does not contain specific emission limits for beryllium, mercury and arsenic from turbines. BACT for heavy metals is typically represented by the level of particulate control. The emission factors for PM/PM_{10} when firing the IGCC with syngas and No. 2 fuel oil are judged to represent BACT for beryllium, arsenic and mercury.

PM/PM_{10} emissions are controlled for the auxiliary boiler by firing with No. 2 fuel oil with a sulfur concentration not to exceed 0.05%, by weight. This fuel sulfur level is consistent with recent BACT determinations for similar facilities.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from combustion turbines are largely dependent upon the completeness of combustion and the type of fuel used. The applicant has indicated that the carbon monoxide emissions from the proposed turbines are based on exhaust concentrations of 25 ppmvd for syngas and 30 ppmvd for No. 2 fuel oil. Volatile organic compound emissions have been based on exhaust concentrations of 7 and 1 ppmvd for fuel oil firing and syngas, respectively.

A review of the BACT/LAER clearinghouse indicates that several of the largest combustion turbines (those with heat inputs greater that 1,000 MMBtu/hour) have been permitted with CO limitations which are similar to those proposed by the applicant. For VOC, the clearinghouse also indicates that the proposed emissions are consistent with that established for other turbines of similar size, thereby suggesting that the proposed emission levels for both CO and VOC are reasonable. Although the majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional control is achievable through the use of catalytic oxidation.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection for NO_x control. These installations have been required to utilize LAER technology, and typically have CO limits in the 10 ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, thereby reducing the amount of thermal energy required compared to thermal oxidation. For CC combustion turbines, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature and desired efficiency. Most gas turbine applications have been limited to smaller cogeneration facilities burning natural gas in nonattainment areas.

The application of oxidation catalyst is not being required as BACT for the IGCC unit due to high content of sulfur in the fuel. Syngas fuel which will be utilized at 100 percent capacity factor contains up to 0.07% by weight sulfur content. These sulfur compounds are oxidized to SO_2 in the combustion process and will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Therefore, the use of an oxidation catalyst system for the IGCC unit is not BACT due to corrosion problems.

Acid Gases - Sulfur Dioxide

The emissions of sulfur dioxide, nitrogen oxides, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent a significant proportion of the total emissions and need to be controlled if deemed appropriate. Sulfur dioxide emissions from combustion turbines are directly related to the sulfur content of the fuel being combusted.

The IGCC facility's projected emissions for SO_2 exceed the significant emission rates given in Florida Administrative Code Rule 17-212.410, Table 212.400-2. A review of the BACT/LAER Clearinghouse indicates that the proposed post-demonstration SO_2 emission level of 0.17 lbs/MMBtu for syngas is consistent with the SO_2 limit for recent determinations of coal fired boilers.

For the IGCC combustion turbine, the applicant has proposed the use of Syngas, No. 2 fuel oil with a maximum sulfur content of 0.05%, by weight, and coal gasification to control sulfur dioxide emissions. In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content syngas and fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation

of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

Coal gasification sulfur content is controlled through fuel-production process controls. Sulfur removal stages in the coal gasification process include acid gas removal, and sulfuric acid plant thermal oxidizer. Acid gas removal systems remove hydrogen sulfide, carbonyl sulfide and carbon dioxide from the fuel gas using an acid gas absorbent solution. The acid gases are stripped from the adsorbent solution and sent to the sulfuric acid plant for introduction into a thermal oxidizer, where the remaining sulfur compounds are converted to SO_2, and finally converted to commercial grade liquid H_2SO_4. The overall sulfur removal efficiency is 95.6%. The sulfur bearing compounds content of the syngas is reduced to 0.07% by weight, or less.

The elimination of flue gas control as a BACT option then leaves the use of NG, CG with the sulfur removal process or low sulfur coal as the options to be investigated. The applicant has proposed the use of syngas, CG with sulfur removal or No. 2 fuel oil (maximum of 876 hours per year per IGCC combustion turbine) with a maximum sulfur content of 0.05%, by weight, as BACT for this project.

Although the applicant's proposed coal gasification acid gas cleanup process is an existing technology, development is continuing on coal gasification systems. The data base to determine whether the proposed post-demonstration sulfur bearing compounds level of 0.07% by weight is reasonable for a coal gasification facility with resulting proposed emissions of 0.17 lbs/MMBtu is limited. A commercial scale demonstration of an IGCC 100 MW power plant has been conducted adjacent to Southern California Edison's Cool Water generating station. During the Cool Water demonstration project, high sulfur coals, Illinois #6 and Pittsburgh #8, with a sulfur content of about 3.1 percent were tested. The SO_2 emission rate was 0.11 lbs/MMBtu for the Pittsburgh #8 coal and was even lower for the Illinois #6 coal (Technical Brief, Cool Water Coal Gasification Program: Commercial Scale Demonstration of IGCC Technology Completed, Electric Power Research Institute). The Polk Power Station IGCC unit has been designed for a larger capacity and is expected to be capable of using coals from various sources not included in the Cool Water demonstration project tests. Although, emission rates from the Cool Water tests are representative of the SO_2 emission range that can be achieved using IGCC units, the study was conducted as a demonstration project and the unit was later converted to another fuel source.

The Polk Power Station IGCC coal gasification system includes an option for both cold gas and hot gas cleanup and emissions from the Cool Water demonstration project are not directly comparable to the hot gas cleanup system. However, an objective of the hot gas cleanup system test is to demonstrate the efficiency in decreasing sulfur emissions compared to cold gas cleanup system.

Acid Gases - Nitrogen Oxides

The applicant has stated that BACT for nitrogen oxides for the IGCC unit will be met by using nitrogen diluent injection to limit emissions to 25 ppmvd at 15% oxygen when burning syngas, and water injection to achieve 42 ppmvd at 15% oxygen when burning No. 2 fuel oil. The emission limit of 25 ppmvd when burning syngas is higher compared to 9 ppmvd when burning NG in a combustion turbine due to the difference in composition and heat content between the two fuels. In contrast to natural gas which is predominately methane, syngas is composed of a variety of constituents including CO, hydrogen, CO_2, nitrogen, and water. The combustible components of syngas are primarily CO and hydrogen instead of methane. CO and hydrogen burn at a higher adiabatic flame temperature than methane and therefore can produce approximately three times as much NO_X as natural gas.

A review of EPA's BACT/LAER Clearinghouse indicates that the lowest NO_X emission limit established to date for a combustion turbine is 4.5 ppmvd at 15 percent oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system. The two 25 MW combustion turbines are located in Kern County, California and the degree of control at this facility exceeds BACT requirements.

Selective catalytic reduction is a post-combustion method for control of NO_X emissions. The SCR process combines vaporized ammonia with NO_X in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed.

The applicant has indicated that the cost effectiveness for the application of SCR technology to the Polk Power Station IGCC project was determined to be $4,935 per ton of NO_X removed for a 50% reduction of NO_X concentration from 25 ppmvd to 12.5 ppmvd. The cost impact analysis was conducted using the OAQPS factors and project-specific economic factors. An assessment of economics impacts was performed by comparing control costs between a baseline case of advanced combustion and nitrogen injection and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_X exhaust concentrations of 25 and 42 ppmvd at 15% oxygen for syngas and oil-firing, respectively. Based

on Japanese experience, SCR technology was premised to achieve NO_x concentration of 12.5 and 21 ppmvd at 15% oxygen for syngas and oil-firing, respectively, representing a 50% NO_x removal efficiency.

Since SCR has been determined to be BACT for several combined cycle facilities firing natural gas, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics. In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products Inc.), the following statement is made:

"In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

The auxiliary boiler is expected to operate 1,000 hours per year or less. The applicant is proposing to control SO_2 and acid gas emissions by firing with No. 2 fuel oil with a sulfur content of 0.05% or less, by weight, and by using combustion controls. Therefore, limited operation and low sulfur distillate oil represents BACT for the auxiliary boiler.

H_2SO_4 Plant Thermal Oxidizer

The predominant emission from the thermal oxidizer is sulfur dioxide. The sulfur dioxide emissions proposed for the facility are based on the highest removal efficiency that is now being maintained at other coal gasification facilities. This is accomplished by using an acid gas removal system followed by a sulfuric plant thermal oxidizer. This process is capable of providing an overall sulfur removal rate of 95.6 percent.

Fugitive Sources

The applicant has indicated that fugitive particulate emissions may result from the storage and handling of coal, slag, and sulfur. BACT for controlling these activities is good engineering design and practices. Control measures shall include the following:

- Minimize number of material transfer points
- Apply crusting agent application to inactive storage areas
- Enclose conveyers and transfer points
- Provide induced collection systems for dust

- Provide wet suppression systems (surfactant)
- Cover by-product storage areas (upon completion of cell)
- Handle and store sulfur in a molten or continuous crystalline state

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Although the use of SCR does have some environmental impacts, the disadvantages do not outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 50 percent. The benefits of NO_x control by using SCR is substantiated by the fact that a number of BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years for combustion turbines.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of syngas and No. 2 fuel oil have been evaluated. Beryllium and Mercury exceeds the PSD significant level. Other toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than one ton per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense for firing with natural gas or fuel oil. Therefore, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of syngas or No. 2 fuel oil.

Potentially Sensitive Concerns

With regard to controlling NOx emissions from SCR the applicant has expressed concerns regarding SCR catalyst deactivation due to poisoning, oxidation of SO2 to SO3, formation of H2SO4, formation of ammonium bisulfate and ammonium sulfate, risk due to potential leaks from storage of NH3 and disposal of spent catalyst which may be considered hazardous.

A review of permitting activities for combined cycle proposals across the nation indicates that SCR has been required or proposed for installations with a variety of operating conditions including firing with fuel oil. SCR also has been accepted as BACT for boilers fired with pulverized coal. Although the concerns expressed by the applicant were valid at one time, the most recent experiences indicate that these problems have been resolved through advances in catalysts and experiences gained in operation.

BACT Determination by DEP

1. Combustion Products - PM/PM_{10} (excluding H_2SO_4)

During the two year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed PM/PM10 emission limit of 0.013 lb/MMBtu is accepted for IGCC hot cleanup testing conducted under the Cooperative agreement with the US DOE.

For IGCC operation following the 2-year demonstration period particulate emissions control for the IGCC unit will be limited to 0.013 lb/MMBtu.

2. Products of Incomplete Combustion - CO and VOC

The use of an oxidation catalyst system for the IGCC system is not found to be BACT due to the high sulfur content in the syngas and resulting corrosion problems. Emissions are to be controlled by good combustion practices during demonstration and post demonstration periods.

3. Acid Gases - Sulfur Dioxides

During the 2-year demonstration period for the IGCC unit at the Polk Power Station, the applicant's proposed SO_2 emissions limit of 0.247 lbs/MMBtu is accepted for IGCC demonstration testing conducted under the Cooperative Agreement with the US DOE. The proposed emissions limit will allow for testing of coals with a broad range of sulfur content and for evaluation of the IGCC unit design.

For IGCC operations following the demonstration period, SO_2 emissions shall not exceed the 0.17 lbs/MMBtu limit established in a recent BACT determination for the Indiantown Cogeneration facility.

The SO_2 emissions shall be limited to 0.17 lbs/MMBtu for the IGCC unit by the use of low sulfur coal and the integral IGCC sulfur removal and recovery processes.

Acid Gases - Nitrogen Oxides

The annualized cost per ton for NO_X removal of $4,935 for the IGCC SCR estimated by the applicant exceeds recent estimates for other applications. Recent published estimates for a pulverized coal plant (Selective Catalytic Reduction for a 460 MW coal fueled unit: Overview of a NO_X Reduction System Selection, EPRI, 1993) with a NO_X reduction of 47 percent was $3,265 per ton in 1997 dollars. Costs per ton in this range indicate SCR is a reasonable alternative. However, there are significant differences between a pulverized coal-fired power plant and an IGCC unit in the design and operation of SCR NO_X control systems.

Due to the uncertainty in actual system performance and high cost of a SCR control system, NO_X BACT for the IGCC CT will be determined following a data collection period. After the demonstration phase, NO_X emission testing will be conducted on the CT every two months over a 12 to 18 month period. Test results will be provided to the Department within thirty (30) days after each test is performed. During the test period, the CT shall be operated to achieve the lowest possible NO_X emission rate and shall not exceed 25 ppmvd NO_X corrected to 15 percent oxygen and ISO conditions. This concentration limitation, equivalent to an emission rate of 0.099 lb NO_X/MMBtu, is 42 percent lower than rates recently established as BACT for other pulverized coal-fired power plant applications. One month after the test period ends, the applicant will submit a recommended BACT determination for NO_X using the test results, data obtained from other similar facilities, and research conducted by the CT manufacturer. The Department will then make a BACT determination for NO_X only and adjust the NO_X emission limits as appropriate.

The emission limits for the IGCC unit for firing with syngas and No. 2 fuel oil for the Polk Power Station are thereby established as follows:

Emission Limitations - 7F CT

Pollutant	IGCC Post Demonstration				IGCC 2-year Demonstration			
	Fuel	Basis	lb/hr	tpy[a]	Fuel	Basis	lb/hr	tpy[b]
NO_x	Oil	42 ppmvd[f]	311	N/A	Oil	42 ppmvd	311	N/A
	Syngas	25 ppmvd[f]	222.5	1,044	Syngas	81 ppmvd	664.2	2,908.3
VOC[c]	Oil	0.025 lb/MMBtu	32	N/A	Oil	0.028 lb/MMBtu	32	N/A
	Syngas	0.0017 lb/MMBtu	3	38.5	Syngas	0.0017 lb/MMBtu	3	38.5
CO	Oil	40 ppmvd	99	N/A	Oil	40 ppmvd	99	N/A
	Syngas	25 ppmvd	98	430.1	Syngas	25 ppmvd	99	430.1
PM/PM_{10}[d]	Oil	0.009 lb/MMBtu	17	N/A	Oil	0.009 lb/MMBtu	17	N/A
	Syngas	0.013 lb/MMBtu	17	74.5	Syngas	0.013 lb/MMBtu	17	74.5
Pb	Oil	5.30E-5 lb/MMBtu	0.101	N/A	Oil	5.30E-5 lb/MMBtu	0.101	N/A
	Syngas	2.41E-6 lb/MMBtu	0.0035	0.067	Syngas	1.10E-5 lb/MMBtu	0.023	0.13
SO_2	Oil[e]	0.048 lb/MMBtu	92.2	N/A	Oil	0.048 lb/MMBtu	92.2	N/A
	Syngas	0.17 lb/MMBtu	357	1563.7	Syngas	0.247 lb/MMBtu	518	2,269

NOTES: a - Based on baseload operations firing syngas, with emission rates equivalent to 100 percent CGCU operations; up to 10 percent annual capacity factor firing fuel oil.

b - Based on baseload operations firing syngas, with a maximum of 8760 hrs/yr utilization of HGCU operations; up to 10 percent annual capacity factor firing fuel oil.

c - Exclusive of background concentrations.

d - Excluding sulfuric acid mist.

e - Sulfur dioxide emissions based on a maximum of 0.05 percent sulfur, by weight.

f - ppmvd at 15% O_2 and ISO conditions.

Auxiliary Boiler

For the auxiliary boiler, BACT will be represented by a limitation on hours of operation and the use of clean fuel (maximum 1,000 hours per year firing No. 2 fuel oil with 0.05% sulfur, by weight).

H_2SO_4 Plant Thermal Oxidizer

A review of the proposed emission rates for the thermal oxidizer indicates that equipment in and of itself represents BACT for these sources.

Fugitive Sources

A review of the control strategy indicates that the applicant has proposed taking all reasonable measures to minimize fugitive particulate emissions and is representative of BACT.

Details of the Analysis May be Obtained by Contacting:
Doug Outlaw, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

February 18 1994
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

February 24 1994
Date