Technical Evaluation
and
Preliminary Determination

Auburndale Power Partners
Auburndale, Polk County, Florida

156 MW Combined Cycle System

Permit Number: AC 53-208321
PSD-FL-185

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

August 6, 1992

IV.

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

Auburndale Power Partners
12500 Fair Lakes Circle, Suite 420
Fairfax, Virginia 22033

II. REVIEWING AND PROCESS SCHEDULE

Date of Receipt of Application: February 2, 1992

Completeness Review: Department letter dated March 10, 1992.

Response to Incompleteness Letters: Company letters received on April 28, May 19, June 18, and July 8, 1992.

Application Completeness Date: May 19, 1992.

III. FACILITY INFORMATION

III.1 Facility Location

This facility is located on County Road 544-A (Derby Avenue) in Auburndale, Polk County, Florida. The UTM coordinates are Zone 17, 420.8 km East and 3103 km North.

III.2 Facility Identification Code (SIC)

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 491 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4911 - Electric and Other Services Combined.

III.3 Facility Category

Auburndale Power Partners proposed project in Auburndale is classified as a major emitting facility. The proposed 156 MW (megawatt) combined cycle system will increase this facility's emissions by approximately 509 tons per year (TPY) of nitrogen oxides (NO_x); 175 TPY of sulfur dioxide (SO_2); 191 TPY of carbon monoxide (CO); 46 TPY of particulate matter (PM); 27 TPY of volatile organic compounds (VOC); 0.014 TPY of beryllium; 0.51 TPY of lead; 0.060 TPY of mercury; and 23 TPY of sulfuric acid mist if operated at 8,360 hours per year on gas and 400 hours per year on fuel oil with a maximum of 0.05 percent sulfur(s) by weight.

IV. PROJECT DESCRIPTION

Auburndale Power Partners proposes to operate a combined cycle system consisting of one 104 MW combustion turbine (CT), Westinghouse 501D, one 52 MW steam turbine (ST), and one unfired heat recovery steam generator (HRSG) and ancillary equipment. This total system is rated at 156 MW output nominal capacity. Natural gas will be the primary fuel for the cogeneration facility over its lifetime. A long-term contract for natural gas has been obtained, and a pipeline to the site is scheduled to be completed by December 1, 1994. No. 2 distillate fuel oil (0.05% S by weight) will be the backup fuel. Fuel oil will be delivered to the site by truck and stored on site in two 600,000 gallon storage tanks. Pending the completion of the natural gas pipeline, fuel oil may be used continuously during the facility's first 18 months of operation. Fuel oil will be used for a maximum of 400 hours per year thereafter. The CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CT for simple cycle operation.

V. RULE APPLICABILITY

The proposed project is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, Chapters 17-2 and 17-4, Florida Administrative Code (F.A.C.), and 40 CFR (July, 1990 version).

The plant is located in an area designated attainment for all criteria pollutants in accordance with F.A.C. Rule 17-2.420.

The proposed project will be reviewed under F.A.C. Rule 17-2.500(5), New Source Review (NSR) for Prevention of Significant Deterioration (PSD), because it will be a major modification to a major facility. This review consists of a determination of Best Available Control Technology (BACT) and unless otherwise exempted, an analysis of the air quality impact of the increased emissions. The review also includes an analysis of the project's impacts on soils, vegetation and visibility; along with air quality impacts resulting from associated commercial, residential and industrial growth.

The proposed source shall be in compliance with all applicable provisions of F.A.C. Chapters 17-2 and 17-4 and the 40 CFR (July, 1991 version). The proposed source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

The source shall be in compliance with the New Source Performance Standards for Gas Turbines, Subpart GG, Appendix A, which is contained in 40 CFR 60, and is adopted by reference in F.A.C. Rule 17-2.660.

VI. SOURCE IMPACT ANALYSIS

VI.1 **Emission Limitations**

The operation of this combined cycle system facility burning No. 2 fuel oil and natural gas will produce emissions of NO_X, SO_2, CO, sulfuric acid mist, PM, As, F, Be, Pb and Hg. The impact of these pollutant emissions are below the Florida ambient air quality standards (AAQS) and/or the acceptable ambient concentration levels (AAC). Table 1 lists each contaminant and its maximum expected emission rates.

VI.2 **Air Toxics Evaluation**

The operation of the sources will produce emissions of chemical compounds that may be toxic in high concentrations. The emission rates of these chemicals shall not create ambient concentrations greater than the acceptable ambient concentrations (AAC) as shown below. Determination of the AAC for these organic compounds shall be determined by Department approved dispersion modeling or ambient monitoring.

$$AAC = \frac{OEL}{\text{Safety Factor}}$$

Where,

AAC = acceptable ambient concentration

Safety Factor = 50 for category B substances and 8 hrs/day
100 for category A substances and 8 hrs/day
210 for category B substances and 24 hrs/day
420 for category A substances and 24 hrs/day

OEL = Occupational exposure level such as ACGIH, ASHA and NIOSH published standards for toxic materials.

MSDS = Material Safety Data Sheets

VI.3 **Air Quality Analysis**

a. Introduction

The operation of the proposed facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: NO_X, SO_2, PM, PM_{10}, Be, CO, VOC, Pb, inorganic arsenic, and H_2SO_4 mist. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-2.500(5) for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;

TABLE 1 - ALLOWABLE EMISSION RATES

Pollutant	Fuel[A]	Allowable Emission Standard/Limitation	Basis
	Gas	15 ppmvd @ 15% O_2 & ISO (78.6 lbs/hr; 344.3 TPY)[B]	BACT
NO_x	Gas	25 ppmvd @ 15% O_2 & ISO (131.0 lbs/hr; 509 TPY)	BACT
	Oil	42 ppmvd @ 15% O_2 & ISO (230.0 lbs/hr; 1,007.4 TPY)	BACT
CO	Gas	21 ppmvd (43.5 lbs/hr; 190.5 TPY)[C]	
	Gas	15 ppmvd (43.5 lbs/hr; 190.5 TPY)	BACT
	Oil	25 ppmvd (73.0 lbs/hr; 319.7 TPY)	BACT
VOC	Gas	6.0 lbs/hr; 26.3 TPY	BACT
	Oil	10.0 lbs/hr; 43.8 TPY	BACT
PM_{10}	Gas	0.0134 lb/MMBtu (10.5 lbs/hr; 46.0 TPY)	BACT
	Oil	0.0472 lb/MMBtu (36.8 lbs/hr; 161.2 TPY)	BACT
SO_2	Gas	40.0 lbs/hr; 175.2 TPY	BACT
	Oil	70.0 lbs/hr; 306.6 TPY	BACT
H_2SO_4	Gas	5.1 lbs/hr; 22.3 TPY	BACT
	Oil	8.9 lbs/hr; 39.0 TPY	BACT
Opacity	Gas	10% opacity	BACT
	Oil	10% opacity	BACT
Hg	Gas	1.10×10^{-5} lb/MMBtu (0.001 lb/hr; 0.06 TPY)	Appl.
	Oil	3.0×10^{-6} lb/MMBtu (0.004 lb/hr; 0.016 TPY)	Appl.
As	Oil	1.61×10^{-4} (0.20 lb/hr; 0.05 TPY)	BACT
F	Oil	3.30×10^{-5} (0.04 lb/hr; 0.17 TPY)	Appl.
Be	Oil	2.0×10^{-6} (0.003 lb/hr; 0.014 TPY)	BACT
Pb	Oil	1.04×10^{-4} (0.13 lb/hr; 0.510 TPY)	BACT

A) Fuel: Natural Gas. Emissions are based on 8360 hours per year operating time burning natural gas and 400 hours per year operating time burning No. 2 fuel oil.

Fuel: No. 2 Distillate Fuel Oil (0.05% S). Emissions are based on 8760 hours per year burning fuel oil.

B) The NO_x maximum limit will be lowered to 15 ppm by 9/30/97 (about 18 months after natural gas is first fired) using appropriate combustion technology improvements or SCR.

C) 21 ppmvd at minimum load.
15 ppmvd at base load.

- A PSD increment analysis (for SO_2, PM, PM_{10}, and NO_x);
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	SO_2	TSP & PM10	NO_x	CO	Be	Pb
PSD de minimus Concentra. (ug/m^3)	13	10	14	575	0.001	0.1
Averaging Time	24-hr	24-hr	Annual	8-hr	24-hr	3 mo.
Maximum Predicted Impact (ug/m^3)	2.8	2.7	0.16	10.3	.0002	<.007

There are no monitoring de minumus concentrations for H_2SO_4 mist and inorganic arsenic. As shown above, the predicted impacts are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for these pollutants.

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Tampa Florida National Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for criteria pollutants SO_2, CO, NO_2, PM and PM_{10}. This evaluation was based on the proposed facility operating at load conditions of 100%, 92°F; 80%, 47°F; and 65%, 29°F. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed unit beginning at 250m and going out at intervals of 250m to a distance of 1500m from the proposed facility. Additional rings were placed at intervals of 2.0, 2.5, 3.0, 4.0, 5.0, 7.5, 10.0, 15.0 and 20.0 km. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for SO_2, CO, NO_2, PM and PM_{10}.

	SO_2			NO2	CO		PM and PM_{10}	
Avg. Time	Annual	3-hr	24-hr	Annual	1-hr	8-hr	Ann.	24-hr
PSD Signifi. Level (ug/m^3)	1.0	25.0	5.0	1.0	2000	500	1.0	5.0
Ambient Concen. Increase (ug/m^3)	0.2	12.6	2.8	0.2	15	10	0.04	1.4

Therefore, further dispersion modeling for comparison with AAQS and PSD Class II increment consumption were not required for these pollutants. Pb has no significant impact level; however, maximum predicted Pb concentrations of 0.007 ug/m^3, 24-hour average were less than the 1.5 ug/m^3 quarterly ambient air quality standard.

Be, inorganic arsenic and H_2SO_4 mist are noncriteria pollutants, which means that neither national AAQS nor PSD Significant Impacts have been defined for these pollutants. However, the Department does have a draft Air Toxics Permitting Strategy, which defines no threat levels for these pollutants. The

Department and the applicant have used the same modeling procedure described above to evaluate the maximum ground level concentrations of these pollutants for comparison with the no-threat levels. The results of this analysis are shown below:

Avg. Time	Be Annual	H_2SO_4 mist 24-hr	As Annual
No Threat-Level (ug/m^3)	0.00042	2.4	.00023
Max. Concen.	0.000003	0.5	.00015

All of these values are less than their respective no-threat levels.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area located about 100 km northwest of the facility. The predicted impact of SO_2 and NO_2 emissions from the proposed project on this area was evaluated by first using the ISCST model to predict maximum increment consumptions by the source alone and by comparing these predicted values to the appropriate recommended significance levels to determine whether further modeling was necessary. The significance levels used by the Department were the more stringent National Park Service (NPS) recommended levels. The predicted maximum NO_2 and SO_2 increment consumptions for all applicable averaging times, except for the SO_2 24-hour average, were less than these significance levels. Therefore, no further modeling for these time periods was required. Since the predicted maximum SO_2 24-hour concentration was predicted to be greater than the NPS levels, the Department and the NPS directed the applicant to further evaluate the SO_2 short term impacts on the Class I area. The applicant used ISCST and modeled the inventory of all PSD increment consuming and expanding sources on the selected days and at the specific receptors where the proposed facility's impacts were significant. The inventory was provided by the Department. Results of this analysis show that on the days and at the location of significant impacts due to the proposed facility, total 24-hour SO_2 impacts at Chassahowitzka were predicted to be less than the allowable 24-hour PSD Class I increment of 5 ug/m^3. Therefore, emissions from the proposed project will not cause or contribute to an exceedance of SO_2 increments.

e. Additional Impacts Analysis

A Level-1 screening analysis using the EPA model, VISCREEN was used to determine any potential adverse visibility impacts on the Class I Chassahowitzka National Wilderness Area located about 100km away. Based on this analysis, the maximum predicted visual impacts due to the proposed project are less than the screening criteria both inside and outside the Class I area. A comprehensive air quality related values (AQRV) analysis for this Class I area was performed by the applicant. No significant impacts on the Class I area are expected.

In addition, the maximum predicted concentrations from NOx, CO, SO_2, PM and PM_{10} are predicted to be less than the AAQS, including the national secondary standards designed to protect public welfare-related values. As such, no harmful effects on soil and vegetation are expected in the area of the project. Also, the proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

VII. CONCLUSION

Based on the information provided by Auburndale Power Partners, the Department has reasonable assurance that the proposed installation of the 156 MW combined cycle system, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-2 of the Florida Administrative Code.

Preston Lewis
#41755

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

PERMITTEE:
Auburndale Power Partners
12500 Fair Lakes Circle, Ste. 420
Fairfax, Virginia 22033

Permit Number: AC 53-208321
PSD-FL-185
Expiration Date: Oct. 30, 1995
County: Polk
Latitude/Longitude: 28°03'15"N
81°48'20"W
Project: 156 MW Combined Cycle System

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 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 made a part hereof and specifically described as follows:

Auburndale Power Partners proposes to operate a combined cycle system consisting of one combustion turbine, one steam turbine, and one heat recovery steam generator and ancillary equipment. This total system is rated at 156 MW output nominal capacity (52 MW output from the steam turbine generator). This facility is located on County Road 544-A (Derby Avenue) in Auburndale, Polk County, Florida. The UTM coordinates are Zone 17, 420.8 km East and 3103 km North.

The sources 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. Auburndale Power Partners (APP) application received February 10, 1992.
2. Department's letter dated March 10, 1992.
3. APP's letter received April 28, 1992.
4. APP's letter received May 19, 1992.
5. APP's letter received June 18, 1992.

GENERAL CONDITIONS:

- 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:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Table 1.

2. Visible emissions shall not exceed 20% opacity except at full load in which case visible emissions shall not exceed 10% opacity.

Operating Rates

3. This source is allowed to operate continuously (8760 hours per year).

4. This source is allowed to use natural gas as the primary fuel and low sulfur No. 2 distillate oil as the secondary fuel (with the conditions specified in Specific Condition No. 5 below).

5. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

a) Maximum low sulfur No. 2 fuel oil consumption for the facility shall be allowed for the equivalent of 18 months (13,140 hours) of the initial facility operation, or until the Florida Gas Transmission (FGT) Phase III expansion is complete and natural gas is available; whichever occurs first. The unit start-up is expected by 10/94 and natural gas would be used by 4/96.

b) Once the FGT Phase III expansion is complete and natural gas is available to the facility, low sulfur No. 2 fuel oil firing shall be limited to 400 hours annually.

SPECIFIC CONDITIONS:

c) Maximum sulfur content in the low sulfur No. 2 fuel oil shall not exceed 0.05 percent by weight.

6. a) The maximum heat input of 1,170 MMBtu/hr at ISO conditions (base load) for distillate fuel oil No. 2.

b) The maximum heat input of 1,214 MMBtu/hr at ISO conditions (base load) for natural gas.

7. Any change in the method of operation, equipment or operating hours shall be submitted to DER's Bureau of Air Regulation.

8. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility may be included in the operating permit.

Compliance Determination

9. Compliance with the NO_x, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input) within 180 days of initial operation and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1991 version) and adopted by reference in F.A.C. Rule 17-2.700.

- Method 1. Sample and Velocity Traverses
- Method 2. Volumetric Flow Rate
- Method 3. Gas Analysis
- Method 5. Determination of Particulate Matter Emissions from Stationary Sources
- Method 9. Determination of the Opacity of the Emissions from Stationary Sources
- Method 8. Determination of the Sulfuric Acid of the Emissions from Stationary Sources
- Method 10. Determination of the Carbon Monoxide Emission from Stationary Sources
- Method 20. Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 25A. Determination of the Volatile Organic Compounds Emissions from Stationary Sources

Other DER approved methods may be used for compliance testing after prior Departmental approval.

10. Method 5 must be performed on this unit to determine the initial compliance status of the unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

SPECIFIC CONDITIONS:

11. Compliance with the SO_2 emission limit can also be determined by calculations based on fuel analysis using ASTM D4292 for the sulfur content of liquid fuels and ASTM D4084-82 or D3246-81 for sulfur content of gaseous fuel.

12. Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

13. Mercury (Hg) shall be tested during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

14. During performance tests, to determine compliance with the proposed NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19} (H_{obs} - 0.00633) \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

15. Test results will be the average of 3 valid runs. The Southwest District office will be notified at least 15 days in writing in advance of the compliance test(s). The sources shall

SPECIFIC CONDITIONS:

operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Southwest District office no later than 45 days after completion.

16. The permittee shall leave sufficient space suitable for future installation of SCR equipment should the facility be unable to meet the NO_x standards, if required.

17. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1991).

18. A continuous monitoring system shall be installed to monitor and record the fuel consumption on each unit. While steam injection is being utilized for NO_x control, the water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

19. Sulfur, nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be based on a weighted 12 month rolling average from fuel delivery receipts. The records of fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

20. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-2 and 17-4, Florida Administrative Code and 40 CFR (July, 1991 version).

21. The sources shall comply with all requirements of 40 CFR 60, Subpart GG, and F.A.C. Rule 17-2.660(2)(a), Standards of Performance for Stationary Gas Turbines.

22. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-2.210(1)).

SPECIFIC CONDITIONS:

23. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

24. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which contruction has not commenced (40 CFR 52.21(r)(2)).

25. Quarterly excess emission reports, in accordance with the July 1, 1991 version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Southwest District office.

26. Literature on equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and steam injection and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Southwest District office and the Bureau of Air Regulation.

27. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

28. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur, nitrogen contents and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Southwest District office by March 1 of each calendar year.

29. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

30. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed

TABLE 1 - ALLOWABLE EMISSION RATES

Pollutant	Fuel[A]	Allowable Emission Standard/Limitation	Basis
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PM_{10}	Gas	0.0134 lb/MMBtu (10.5 lbs/hr; 46.0 TPY)	BACT
	Oil	0.0472 lb/MMBtu (36.8 lbs/hr; 161.2 TPY)	BACT
SO_2	Gas	40.0 lbs/hr; 175.2 TPY	BACT
	Oil	70.0 lbs/hr; 306.6 TPY	BACT
H_2SO_4	Gas	5.1 lbs/hr; 22.3 TPY	BACT
	Oil	8.9 lbs/hr; 39.0 TPY	BACT
Opacity	Gas	10% opacity	BACT
	Oil	10% opacity	BACT
Hg	Gas	1.10×10^{-5} lb/MMBtu (0.001 lb/hr; 0.06 TPY)	Appl.
	Oil	3.0×10^{-6} lb/MMBtu (0.004 lb/hr; 0.016 TPY)	Appl.
As	Oil	1.61×10^{-4} (0.20 lb/hr; 0.05 TPY)	BACT
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Be	Oil	2.0×10^{-6} (0.003 lb/hr; 0.014 TPY)	BACT
Pb	Oil	1.04×10^{-4} (0.13 lb/hr; 0.510 TPY)	BACT

A) Fuel: Natural Gas. Emissions are based on 8360 hours per year operating time burning natural gas and 400 hours per year operating time burning No. 2 fuel oil.

Fuel: No. 2 Distillate Fuel Oil (0.05% S). Emissions are based on 8760 hours per year burning fuel oil.

B) The NO_x maximum limit will be lowered to 15 ppm by 9/30/97 (about 18 months after natural gas is first fired) using appropriate combustion technology improvements or SCR.

C) 21 ppmvd at minimum load.
15 ppmvd at base load.

Best Available Control Technology (BACT) Determination
Auburndale Power Partners
Polk County

The applicant proposes to install a combustion turbine generator at their facility in Polk County. The generator system will consist of one nominal 104 megawatt (MW) combustion turbine (CT), with exhaust through heat recovery steam generator (HRSG), which will be used to power a nominal 52 MW steam turbine.

The combustion turbine (Westinghouse 501D) will be capable of combined cycle operation. The applicant requested that the combustion turbine use oil (0.05% S by weight) for the first eighteen (18) months; thereafter, they will use natural gas. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity factor and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Oil	Gas/Oil	PSD Significant Emission Rate (TPY)
NO_x	1,007	509	40
SO_2	307	175.2	40
PM/PM_{10}	161	46	25/15
CO	320	190	100
VOC	44	27	40
H_2SO_4	39	23	7
Be	0.01	0.01	0.0004
As	0.05	0.05	0.1
Pb	0.51	0.51	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

February 2, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 for oil firing
SO_2	0.05% sulfur by weight
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, 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, than 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 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 (e.g., particulates). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.

- Acid Gases (e.g., NO_x). 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.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not exceed 0.013 and 0.047 lb/MMBtu, respectively. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Arsenic, Berylium (Pb, As, Be)

The Department agrees with the applicant's rationale that there are no feasible methods to control lead, beryllium, and arsenic; except by limiting the inherent quality of the fuel.

Although the emissions of these 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. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed turbine is on exhaust concentrations of 15 ppmvd for natural gas firing and 25 ppmvd for fuel oil firing.

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 postcombustion 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. These installations have been required to use 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, which reduces the amount of thermal energy required. For CT/HRSG combinations, 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.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for natural gas-fired unit; however, the cost effectiveness of $7,099 per ton of CO removed will have an economic impact on this project.

The Department is in agreement with the applicant's proposal of combustor design and good operating practices as BACT for CO and VOCs for this cogeneration project.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using steam injection and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NOx emissions. The SCR process combines vaporized ammonia with NOx 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 SCR process can achieve up to 90% reduction of NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease to approximately 86 percent.

Although technically feasible, the applicant has rejected using SCR because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.
b) Ammonia slip.
c) Disposal of hazardous waste generated (spend catalyst).
d) A total SCR energy penalty of 14,911 MMBtu/yr, which is equivalent to the use of 14.2 million ft^3 of natural gas annually, based on a gas heating value of 1,050 Btu per ft^3.
e) Since several schools are located within close proximity to the site, the Polk County Planning Commission and the school boards have expressed concern over the potential for ammonia (NH_3) exposure to high concentration and storage, as well.
f) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
g) Cost effectiveness for the application of SCR technology to the Auburndale cogeneration project was considered to be $6,900 per ton of NO_x removed.

Since SCR has been determined to be BACT for several combined cycle facilities, 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 was 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."

For fuel oil firing, the cost associated with controlling NO_X emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_X injection ratio. For natural gas firing operation NO_X emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_X can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for this project at 100 percent capacity factor is $2,283,326. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using steam injection and advanced combustor design will be 509 tons/year. Assuming that SCR would reduce the NO_X emissions by 65%, about 178 tons of NO_X would be emitted annually. When this reduction (331 TPY) is taken into consideration with the total levelized annual cost of $2,283,326; the cost per ton of controlling NO_X is $6,900. This calculated cost is higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmv (natural gas) using low-NO_X burner technology. Based on the equipment selected, the applicant could not achieve that limit (15 ppmv) due to the fact that it is technically infeasible since their vendor, Westinghouse, does not presently offer this technology. The applicant and their CT vendor, Westinghouse, have agreed to lower NO_X to 15 ppm by 9/30/97. This lower NO_X limit will be achieved by application of low-NO_x burners or SCR. Therefore, the Department has accepted the steam injection and advanced combustor design as BACT for a limited time (up to 9/30/97).

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant has stated that sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions when firing fuel oil will be controlled by lowering the operating time to 400 hours/year per unit and the fuel oil sulfur content to a maximum of 0.05 % by weight. This will result in an annual emission rate of 175 tons SO_2 per year and 23 tons H_2SO_4 mist per year.

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 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."(23). 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."(23). 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 open literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option then leaves the use of low sulfur fuel oil as the next option to be investigated. Auburndale Power Partners, as stated above, has proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. The Department accepts their proposal as BACT for this project.

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost of controlling NO_x ($6,900/ton) is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept steam injection and advanced combustor design as BACT for a limited time (up to 9/30/97).

The Department will revise and lower the allowable BACT limit for this project no later than 9/30/97. It is the Department's understanding that Westinghouse will develop new combustor technology within this period. If the 15 (gas)/42 (oil) ppmvd emission rates cannot be met by September 30, 1997, SCR will be installed. Therefore, the permittee shall install a duct module suitable for future installation of SCR equipment.

SO_2 Control

BACT for sulfur dioxide is the burning of fuel oil No. 2 with 0.05% sulfur content by weight.

VOC and CO Control

Combustion control will be considered as BACT for CO and VOC when firing natural gas.

Other Emissions Control

The emission limitations for PM and PM_{10}, Be, Pb, and As are based on previous BACT determinations for similar facilities.

The emission limits for Auburndale Power Partners project are thereby established as follows:

Pollutant	Emission Standards/Limitations Oil[(a)]	Gas[(b)]	Method of Control
NO_x	42 ppmv	25 ppmv[(c)] 15 ppmv	Steam Injection
CO	73 lbs/hr	44 lbs/hr	Combustion
PM & PM10	37 lbs/hr	10 lbs/hr	Combustion
SO_2	70 lbs/hr	40 lbs/hr	No. 2 Fuel Oil (0.05% S)
H_2SO_4	89 lbs/hr	5.1 lbs/hr	No. 2 Fuel Oil (0.05% S)
VOC	10 lbs/hr	6 lbs/hr	Combustion
Pb	0.13 lb/hr		Fuel Quality
As	0.20 lb/hr		Fuel Quality
Be	0.003 lb/hr		Fuel Quality

(a) No. 2 fuel oil burning for the first eighteen (18) months of operation. Max. 0.05% S by weight.
(b) Natural gas (8360 hours per year), Fuel oil (400 hours per year).
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppm at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppm at 15% oxygen at the earliest achievable date based on steam injection technology or any other technology available, but no later than 9/30/97.

Details of the Analysis May be Obtained by Contacting:

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Recommended by:

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

_______________ 1992
Date

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

_______________ 1992
Date