AUBURNDALE POWER PARTNERS, L.P.
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June 17, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Quality Management
Florida Department of Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: AUBURNDALE COGENERATION PROJECT - PSD-FL-185, AC 53-208321

Dear Mr. Fancy:

In follow-up to our meeting on Friday, June 5 with Mr. Preston Lewis and Ms. Theresa Heron, enclosed is the requested additional information as follows:

(1) Comments on vendor SCR costs obtained by FDER (Attachment I)

(2) A proposal for lower NOx emission rates based on the staged development of Westinghouse's low Nox combustion turbine burner technology. A compliance proposal for fuel oil use is also provided. (Attachment II)

Vendor information on SCR costs provided by FDER consisted of a letter from Norton Chemical Process Corporation and a paper by Ellison Consultants prepared for the Manufacturers of Emission Controls Association. In general, SCR cost estimates previously provided by Auburndale Power Partners in the February 1992 permit application are in agreement with estimates contained in the Norton letter with the exception of catalyst replacement costs. SCR cost estimation procedures contained in the Ellison paper conflict with the Norton data with respect to installation costs and catalyst replacement frequency and will result in SCR costs which we feel significantly underestimate actual costs. Detailed comments on these two documents are provided in Attachment I.

With regards to the NOx emission proposal, our turbine vendor, Westinghouse has indicated that the expected date a new combustor would be available that could achieve the 15 ppm NOx on gas and 42 ppm NOx on oil with steam injection on a sustainable basis would be

(continued)

in five years. As promised, enclosed is test data supplied by Westinghouse for their Bellingham Cogeneration Plant which documents emission rates currently achievable on a sustained basis with their combustor technology.

We are requesting from FDER five years with NOx emissions of 25 ppm on natural gas and 42 ppm on distillate oil, with the understanding that Auburndale Power Partners (APP) will retrofit with the new combustor as soon as it is available to achieve the 15 ppm on natural gas and 42 ppm on oil. If the 15/42 emission rates cannot be met within five years, SCR will be installed.

Reiterating some of the points made in our meeting we feel should support FDER concurrence with this proposal:

(1) APP has voluntarily proposed use of a low sulfur fuel oil that exceeds current FDER BACT requirements.

(2) We are contractually obligated to a turbine vendor who cannot now achieve emissions consistently below 25 ppm and 42 ppm on natural gas and fuel oil with their steam injection technology.

(3) Contrasting our facility from the Orlando Cogen facility, it is much more difficult to obtain 15 ppm on natural gas for a dual fuel fired combustor, where 42 ppm is required for compliance when burning fuel oil.

(4) We have demonstrated that SCR is not cost effective for our project, and that many adverse environmental impacts would result from it's use.

Mr. Fancy, I appreciate you and your staff's time and consideration of our proposal and look forward to discussing it with you, either by phone or in another meeting, in the near future. If you or your staff have any questions on the materials provided, please contact either me at (703) 222-0445 or Tom Davis at ECT (904) 336-0444.

Sincerely,

Patricia A. Haslach

Patricia A. Haslach
Environmental Manager

Attachments
cc:w/attach: Tom Davis, ECT
Jeff Meling, ECT
George Schott, Westinghouse
Don Fields, Mission

Bellingham Cogeneration Plant
Emission Test Summary

Date: 08/30/91 Fuel: Natural Gas Turbine No. 1

PARAMETER	Emission Limit	Run 1	Run 2	Run 3	Test Average
Operating Parameters					
Volumetric Air Flow (ACFM)		961,111	990,923	979,606	977,213
(DSCFM)		617,755	652,040	641,507	637,101
Oxygen (%) dry basis		14.93	14.91	14.86	14.90
Carbon Dioxide (%) dry basis		3.20	3.23	3.27	3.23
Moisture (%) Flue Gas		14.10	12.40	13.40	13.30
Dry Bulb/Wet Bulb (°F)		88.0/74.0	88.0/74.0	84.0/75.8	86.67/74.60
Total Suspended Particulates (TSP)*					
(lbs/hour)	6	5.21	5.21	3.13	4.52
(lbs/MMBtu, HHV)	0.0047	0.0046	0.0049	0.0029	0.0041
Sulfur Dioxide**					
(lbs/hour)	2	0.0	0.0	0.0	0.0
(lbs/MMBtu, HHV)	0.0016	0.0	0.0	0.0	0.0
Nitrogen Oxides					
(lbs/hour)	110	99.53	99.50	98.30	99.11
(lbs/MMBtu, HHV)	0.0859	0.0809	0.0773	0.0770	0.0784
(ppmvd @ 15% O_2)	---	22.23	20.98	20.89	21.37
(ppmvd @ 15% O_2) ISO	25	24.72	23.30	24.52	24.18
Carbon Monoxide					
(lbs/hour)	66	2.33	2.16	2.01	2.17
(lbs/MMBtu, HHV)	0.0516	0.0018	0.0017	0.0016	0.0017
(ppmvd @ 15% O_2)	25	0.81	0.71	0.70	0.74
Total Hydrocarbons (as carbon)					
(lbs/hour)	5.5	1.20	0.71	0.88	0.93
(lbs/MMBtu, HHV)	0.0043	0.0010	0.0005	0.0007	0.0007
(ppmvd @ 15% O_2)	---	1.03	0.57	0.71	0.77
Opacity (%)	10	0.0	0.0	0.0	0.0

* These tests completed September 21, 1991 - see plant operating data for this date.
** Calculated from fuel analysis

Bellingham Cogeneration Plant
Emission Test Summary

Date: 08/29/91 Fuel: Natural Gas Turbine No. 2
BASE LOAD TESTS

PARAMETER	Emission Limit	Run 1	Run 2	Run 3*	Test Average
Operating Parameters					
Volumetric Air Flow (ACFM)		873,531	949,959	979,990	934,493
(DSCFM)		600,798	623,052	653,839	625,896
Oxygen (%) dry basis		14.71	14.72	14.77	14.73
Carbon Dioxide (%) dry basis		3.37	3.37	3.38	3.37
Moisture (%) Flue Gas		9.40	13.30	12.30	11.60
Dry Bulb/Wet Bulb (°F)		87.0/71.5	85.0/71.0	85.0/73.0	85.7/71.8
Total Suspended Particulates (TSP)					
(lbs/hour)	6	1.42	1.47	7.12	3.34
(lbs/MMBtu, HHV)	0.0047	0.0012	0.0012	0.0054	0.0026
Sulfur Dioxide**					
(lbs/hour)	2	0.0	0.0	0.0	0.0
(lbs/MMBtu, HHV)	0.0016	0.0	0.0	0.0	0.0
Nitrogen Oxides					
(lbs/hour)	110	92.10	91.85	93.68	92.54
(lbs/MMBtu, HHV)	0.0859	0.0750	0.0724	0.0709	0.0728
(ppmvd @ 15% O_2)	---	20.40	19.65	19.25	19.77
(ppmvd @ 15% O_2) ISO	25	21.85	21.18	21.40	21.48
Carbon Monoxide					
(lbs/hour)	66	1.16	0.84	1.35	1.12
(lbs/MMBtu, HHV)	0.0516	0.0010	0.0007	0.0010	0.0009
(ppmvd @ 15% O_2)	25	0.42	0.29	0.46	0.39
Total Hydrocarbons (as carbon)					
(lbs/hour)	5.5	0.955	1.072	1.687	1.238
(lbs/MMBtu, HHV)	0.0043	0.0008	0.0008	0.0013	0.0010
(ppmvd @ 15% O_2)	---	0.81	0.88	1.33	1.01
Opacity (%)	10	0.0	0.0	0.0	0.0

* Particulate Run No. 3 completed 08/29/91 Runs 1 and 2 completed 09/22/91
** Calculated from fuel analysis
See plant operating data from this date.

Attachment I
Review of SCR Costs

Comments on the documents provided by FDER regarding SCR costs are provided as follows:

A. Norton Chemical Process Products Corporation letter to FDER dated May 20, 1992.

<u>Capital Costs</u>

SCR purchased equipment cost (PEC) is estimated by Norton to be "on the order of" $2,000,000 for a Westinghouse W501D combustion turbine. This estimate is in close agreement with the $2,275,000 value provided in the February 1992 permit application. Installation cost is estimated by Norton to be 50% of the PEC. Data provided in the February 1992 permit application estimated installation costs to be 30% of PEC (excluding site preparation) using recommended EPA OAQPS factors. The original estimate is therefore conservative (i.e., under-estimates installation costs) in comparison to the Norton data. Total capital costs, using the Norton data, is calculated to be $3,000,000.

It is noted that Norton did not consider indirect costs (engineering, construction & field expenses, contractor fees, start-up, performance tests, and contingencies) or interest during construction in their discussion of capital costs. These costs, which were estimated in the permit application using EPA OAQPS recommended factors, will increase direct capital costs by approximately 50% for a total of $4,500,000. The Norton capital cost data, when adjusted for indirect costs and interest during construction, is consistent with the February 1992 application estimate of $4,717,075.

<u>Annual Operating Costs</u>

Norton indicates a catalyst replacement frequency for SCR systems installed on gas-fired combustion turbines to be from 2 to 5 years. The SCR catalyst replacement frequency of 3 years premised in the Auburndale project permit application is therefore consistent with the Norton data. Catalyst replacement cost is estimated by Norton to be "on the order of" $600,000 which is lower than the $1,170,000 value provided by Westinghouse. It is believed that Norton has significantly under-estimated catalyst replacement costs; use of a correlation obtained from the Ellison paper yielded an estimated catalyst cost of $1,758,006 for the Westinghouse W501D turbine which exceeds the estimate of $1,170,000 contained in the February 1992 permit application. It is noted that SCR catalyst varies in quality and price which may explain the different cost estimates. In addition, the Norton estimate does not appear to include labor costs associated with catalyst replacement.

Norton did not consider a number of other costs associated with the operation of a SCR system, including labor and material, catalyst inventory and disposal, utilities (electricity and ammonia), energy penalties, and indirect costs (overhead, administration, property taxes, insurance, capital recovery). These additional costs would significantly increase total annual operating expenses.

B. Paper by Ellison Consultants prepared for the Manufacturers of Emission Controls Association dated July, 1991.

General

The Ellison paper suggests that SCR costs can be estimated using empirical correlations. The correlations (least squares curve fits) were developed based on questionnaires completed by U.S. SCR vendors. It is noted that foreign SCR vendors (Hitachi, Mitsubishi, Kawasaki, etc.) dominate the U.S. SCR market. *Exclusion of these vendors from the Ellison survey is felt to be a major deficiency.*

Without having access to the underlying data, it is not possible to confirm the accuracy of the correlations or to assess the "scatter" of the data; i.e., the paper did not include any discussion of the variability of the data, correlation coefficients, etc.

The Ellison correlations are stated to be applicable to exhaust flow rates of 100 to 700 pounds per second (lb/sec). The exhaust flow rate for the Westinghouse W501D turbine planned for the Auburndale project is 875 lb/sec, which is outside of the applicable range of the Ellison correlations.

Attachment I
Review of SCR Costs
(continued)

Capital Costs

Excluding installation cost and site preparation, purchased equipment costs for a SCR system using the Ellison paper correlation for natural gas firing and 80% control efficiency yields a result which is in close agreement with the estimate provided in the February 1992 permit application:

Ellison Correlation ($)	February 1992 Application ($)
2,170,687	2,275,000

The Ellison paper installation cost correlation yields an estimate which is only 8.4% of the PEC. This is believed to be a significant under-estimation and is in conflict both with EPA OAQPS factors (30% of PEC) and the Norton vendor estimate (50% of PEC).

The Ellison paper discussion of capital costs omits a number of significant cost items which should be considered; i.e., site preparation, indirect costs (engineering, construction & field expenses, contractor fees, start-up, performance tests, and contingency), and interest during construction. Inclusion of these costs will increase the direct capital cost estimate by approximately 50%.

Annual Operating Costs

There are several premises stated in the Ellison paper which have a major impact on annual operating costs. These premises include: (1) frequency of catalyst replacement of 8 and 5 years for gas and oil firing, respectively, (2) calculation of cost effectiveness ($/ton) based on reducing NO_x from 42/65 ppmvd to 8.4/13 ppmvd for gas and oil firing, respectively, and (3) a capital recovery factor (CRF) of 11%.

Cost associated with catalyst replacement is a significant component of SCR operating expenses. The frequencies cited in the Ellison paper are felt to be extremely optimistic and are in conflict with the Norton letter data. A catalyst replacement frequency of every 3 years for gas firing is considered to be typical.

Use of a 42/65 ppmvd baseline instead of a 25/42 level will result in significant differences in cost effectiveness in terms of dollars per ton of NO_x removed. The Auburndale permit application provided an estimate of incremental cost effectiveness using a 25/42 ppmvd baseline and SCR controlled rates of 9/13 for gas and oil firing, respectively consistent with previous BACT analyses reviewed and approved by the FDER.

The CRF is a function of interest rate and project life and will vary from project to project. As stated in the February 1992 permit application, an interest rate of 13.5% and control system life of 15 years was premised for the Auburndale project which results in a CRF of 15.9%. The 11% CRF used in the Ellison paper is felt to be too low, adding to their under-estimation of annual costs.

The Ellison correlation for annual operating costs also omits consideration of energy penalties, downtime for catalyst replacement, and indirect costs including overhead, administrative charges, property taxes, insurance, and contingencies.

Due to the differences in catalyst replacement frequency, baseline emissions, CRF, and omission of indirect and other operating costs, estimates of annual operating costs would be expected to be much lower using the Ellison correlations. As stated previously, the catalyst replacement frequencies cited in the Ellison paper are unreasonably optimistic and inconsistent with other vendor data.

C. Conclusions

In conclusion, the SCR costs previously submitted to the FDER for the Auburndale project are felt to be reasonable estimates of actual costs. The cost estimates provided in the application are generally consistent with the Norton letter estimates and prior BACT analyses submitted to FDER. The Ellison study is felt to be flawed due to the omission of foreign SCR vendors from their survey, use of unreasonable premises with respect to installation costs and catalyst replacement frequency, use of different baseline emission levels, and omission of significant energy penalty and indirect costs.

ATTACHMEMT II

AUBURNDALE POWER PARTNERS
NOx AND FUEL OIL BACT COMPLIANCE PROPOSAL

SPECIFIC CONDITIONS:

Emission Limits

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

2. Initial NOx emission rates for natural gas firing shall not exceed 25 ppm at 15% oxygen on a dry basis. The permittee shall achieve NOx emissions of 15 ppm at 15% oxygen at the earliest achievable date based on steam injection technology, but no later than five years from permit issuance date.

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 5 below).

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

- 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 FGT Phase III expansion is complete and natural gas is available; whichever occurs first.

- 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.

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

Compliance Determination

6. Steam injection shall be utilized for NOx control. The water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. In addition, the Permittee shall install a duct module suitable for future installation of SCR equipment.