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Orlando Utilities Commission
Stanton Energy Center Unit 2

B&V Project 16805
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November 13, 1991
FEDERAL EXPRESS

Air, Pesticides and Toxics Management Division
U.S. Environmental Protection Agency, Region IV
345 Courtland Street, NE
Atlanta, GA 30365

Subject: OUC Comments and Objections to EPA's Preliminary Determination and Draft Permit Modifications for PSD-FL-084 for Stanton 2

Attention: Mr. R. Scott Davis

Gentlemen:

Enclosed are Orlando Utility Commission's comments and objections regarding the United States Environmental Protection Agency Region IV Preliminary Determination and Draft Permit Modifications for the Prevention of Significant Deterioration for Orlando Utilities Commission's Stanton Energy Center Unit 2 (PSD-FL-084). If you have any questions, please contact James S. Crall at 407-423-9141 or myself at 913-339-2276.

Very truly yours,

BLACK & VEATCH

Z Funke

For Hal E. Smith

brj
Enclosure

cc: Thomas B. Tart
James S. Crall
Ken Van Assenderp
B. Owen
A. Lewis
A. Meng
E. Collins

Orlando Utilities Commission
Stanton Energy Center Unit 2
PSD-FL-084

Comments on EPA Region IV Preliminary Determination

On September 20, 1991, the United States Environmental Protection Agency (EPA) Region IV issued a preliminary determination and draft permit modifications for the Prevention of Significant Deterioration (PSD) for Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 2 (PSD-FL-084). The due date for comments to these documents was originally October 29, 1991. However, the comment period was extended to November 14, 1991 after proper notice was given to OUC and other parties.

With particular regard to NO_x emission control technology, the EPA Region IV, and Florida DER are in unanimous agreement that NO_x emission levels shall be reduced to no more than 0.17 lb/MBtu (30 day rolling average). OUC is committed to make its best effort to achieve this level for NO_x emissions at a reasonable cost.

EPA Region IV, Florida DER, and OUC further agree that determination of the appropriate technology to enable Stanton 2 to meet and maintain this substantially reduced emission level will set an important landmark national precedent in the control of these emissions. That is why both the preliminary determination and draft permit modifications provide for time and flexibility within which OUC can work with EPA Region IV, New Source Review Section (RTP), and Florida DER to derive the most optimum control technology to meet these stringent requirements from both a compliance and enforceability perspective. This innovative and cooperative methodology furthermore is recognized by all concerned to be consistent with and specifically authorized by 40 CFR 52.21(b)(12) which states "Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

Orlando Utilities Commission has an unsurpassed record for environmental compliance. Voluntarily, OUC has consistently maintained Stanton Energy

Center Unit 1 sulfur dioxide and nitrogen oxides emissions well below permitted standards. Permitted SO_2 emissions for Unit 1 are limited to 1.14 lb/MBtu with no less than 90 percent removal or 0.60 lb/MBtu with no less than 70 percent removal. Permitted NO_x emission are 0.60 lb/MBtu. The following summarizes the Unit 1 performance to date.

- Average SO_2 emissions - 0.18 lb/MBtu
- Average SO_2 removal efficiency - 85.3 percent
- Average NO_x emissions - 0.40 lb/MBtu

OUC is committed to ensuring that environmental regulations and standards are maintained to the highest degree of confidence. OUC's compliance record demonstrates this initiative. OUC wants to maintain this performance record for Stanton Energy Center Unit 2. Accordingly, OUC is concerned with some of the specific requirements dictated in the EPA's preliminary determination and draft permit modifications for Unit 2. These concerns are illustrated in subsequent sections of this document. Attached in Appendix A is a markup of the preliminary determination and the draft permit modifications detailing changes recommended by this document.

Sulfuric Acid Mist Emissions

Sulfuric acid mist emissions are regulated under the federal PSD program. For facilities similar to Unit 2, approximately one percent of the sulfur in the coal will form sulfur trioxide (SO_3). This SO_3 will subsequently react with moisture in the flue gas stream to form sulfuric acid mist (H_2SO_4). Uncontrolled emission estimates of H_2SO_4 from Unit 2 were estimated to average 232 lb/h with a worst case emission estimated to be 280 lb/h. These revised sulfuric acid mist emission estimates provided on September 25, 1991 during the Unit 2 Site Certification Application hearing did not assume the use of a selective catalytic reduction (SCR) nitrogen oxides (NO_x) emission control system.

Page 17 of the preliminary determination discusses that "The current status of 'sulfur resistant' catalysts on the market is such that manufacturers will guarantee that SO_2 to SO_3 conversion will be limited to less than 1%." This additional one percent conversion added to the one percent already converted to SO_3 without the SCR represents a potential 100 percent increase in SO_3 emissions. Additional sulfur trioxide emissions result from an increased propensity by SO_2 molecules to oxidize during exposure to catalyst elements.

This sulfur trioxide can react with either unreacted ammonia (if present) from the SCR system to form ammonia sulfate salts, or with moisture in the flue gas to form H_2SO_4 (after the wet limestone scrubber). Some removal of these ammonia salts and unreacted SO_3 from the flue gas stream could be achieved by the electrostatic precipitator and the wet limestone scrubber.

Sulfuric acid mist emissions are important with regard to opacity related considerations and for localized fallout and respiratory effects. At this point, based on the limited amount of information related to increases in SO_3 emissions across the SCR catalyst and ultimate disposition of these SO_3 emissions, it is not possible to predict an expected outcome with certainty. Therefore, for the purpose of establishing permit limitations associated with the potential use of an SCR system it is necessary to increase estimated sulfuric acid mist emissions to a worst case condition of 560 lb/h.

Ammonia Slip Emissions

Page 17 of the preliminary determination indicates that fly ash from Unit 2 will be used in clinker production for the cement industry. Thus, the EPA concluded that concerns documented by OUC regarding spontaneous release of ammonia from fly ash were insignificant, however, fly ash from the Stanton Energy Center is either fixated with scrubber sludge and disposed of in an onsite landfill or sold for commercial use as discussed hereinafter. Thus, concerns related to ammonia slip emissions with regard to on-site disposal are significant. A major portion of the unreacted ammonia (ammonia slip) from post combustion NO_x control system operation will condense onto fly ash particles. A portion of this fly ash is subsequently used to fixate flue gas desulfurization system reaction products. As such, mixture of alkaline fly ash (contaminated with ammonia) with wet alkaline FGD reaction products will result in a spontaneous ammonia release. Higher levels of ammonia slip will result in greater quantities of ammonia absorbed onto fly ash particles.

The fly ash sold by the Stanton Energy Center is <u>not</u> used for clinker production. It is currently used as admixture for cement production with levelized sales of approximately $1 million annually. Accordingly, raw fly ash is mixed with alkaline cement additives providing an environment for spontaneous release of ammonia. In addition, further uses are being developed for high strength, light weight masonry products. The potential release of ammonia from these operations is of significant concern and is generally considered unacceptable as a secondary pollution source and as a direct loss of revenue from fly ash sales.

Dependent on the ash content of the coal, acceptable ammonia slip for these landfill disposal and fly ash sale operations could range between 2 and 5 ppm and represents a delicate balance between the environmentally sound practice of disposing of fly ash and scrubber sludge in a controlled onsite landfill and selling the majority of fly ash for reuse.

Coals with higher ash contents could accommodate higher ammonia slip limits. However, these higher ash contents will lead to higher particulate emissions and based upon the available coal options for this unit are also characteristic of higher sulfur coals which are precluded from consideration due to the preliminary determination limits on SO_2 emissions.

Catalyst Poisoning/Life

SCR systems have not been used at facilities burning eastern United States coal. As such, OUC has significant concern regarding the effect of trace elements on catalyst life. The most significant catalyst poisons are arsenic and alkali elements. For example, average arsenic concentrations (the most active catalyst poison) for eastern US coals are three to four times the worldwide average. The average and maximum expected arsenic concentrations for OUC coal is 22 and 113 ppm, respectively. The average worldwide arsenic concentration is 5.0 ppm. Therefore, considering the level of SCR demonstration status in the United States it is reasonable and prudent that caps on potential catalyst life be included in the final PSD permit.

Precedent for this recommendation has already been established in the PSD permit issued for the Chambers Cogeneration Project to be located in Carneys Point, New Jersey. In this permit, catalyst replacements were limited to no more than 50 percent of the initial catalyst charge within each 5-year operating period. This permit condition was drafted to maintain a Lowest Achievable Emission Rate (LAER) NO_x emission limit of 0.10 lb/MBtu consistent with nonattainment status for VOC emissions (ozone). Recognizing the uncertainties associated with transfer of this technology, this permit allowed a maximum emission of 0.17 lb/MBtu should this catalyst life threshold be exceeded. Similarly, for Unit 2 considering the higher allowable BACT NO_x emission limit for Unit 2, but also considering the SCR synergy for fly ash sales and waste fixation (related to zero water discharge status from the Stanton site and the sound environmentally balanced disposal practices currently utilized in the plant design) it is recommended that should an SCR system be used, catalyst changeouts be limited to no more than 50 percent of the initial catalyst charge within each 5-year operating period. Should changeouts exceed this threshold an appropriate NO_x emission limit will be established up to a maximum of 0.22 lb/MBtu.

Nitrogen Oxides Determination

As stated on page 24 of the preliminary determination and page 3 of the draft permit modifications the basis of the nitrogen oxides emission limitation is use of a SCR system designed to achieve a NO_x emission of 0.1 lb/MBtu. However, discussion on page 24 of the preliminary determination indicated that to maintain unit reliability and to minimize ammonia slip emissions the NO_x emission limit established by the EPA for Unit 2 is 0.17 lb/MBtu on a 30-day rolling average. In addition, the preliminary determination and the draft permit modifications provided flexibility for permit revisions to incorporate the use of a technology other than SCR (either low NO_x burners, selective non-catalytic reduction, or other alternative NO_x emission control technologies) for use on Unit 2. The permit determination and the draft permit modifications also indicate that permit revisions are required should OUC be capable of demonstrating the capability of an alternate NO_x emission control technology. OUC does not feel that permit revisions should be necessary to obtain this flexibility.

As previously stated, the nitrogen oxides emission limit for Unit 2 has been set at 0.17 lb/MBtu. Design of a post combustion NO_x control system for a LAER emission level of 0.1 lb/MBtu adds substantial cost to the project above the considerable cost impact already agreed to for reducing NO_x emissions from 0.32 to the BACT level of 0.17 lb/MBtu. A requirement for a LAER design target of 0.1 lb/MBtu also eliminates consideration or development of more cost effective systems such as a selective non-catalytic reduction (SNCR) systems, or a hybrid of SNCR and SCR systems.

This position as earlier referenced is further substantiated by the statutory definition of BACT determinations in 40 CFR 52.21(b)(12). Accordingly, a source is free to select the means of meeting emission limitations insofar as compliance is maintained with said and enforceable standard. This flexibility allows source owners and engineers to select either existing or newly developed, cost effective, reliable control technologies. Therefore, OUC, in exercising its right independently to select control technologies, must make sure such technologies are capable of meeting the Unit 2 NO_x emission limit of 0.17 lb/MBtu (30 day rolling average). In addition, no permit revisions should be required for this flexibility. The independent determination of NO_x emissions control technology will also ensure that adverse impacts on unit availability are minimized. Based on the legislated definition of BACT all references specifically requiring a SCR system and all references to a design target of 0.1 lb/MBtu should be removed from the final determination and permit modifications, consistent with the operative terms and regulatory thrust of the preliminary determination and the draft permit modifications.

Ammonia Storage Considerations

Page 3 of the draft permit modifications dictates the use of aqueous ammonia (less than 28 percent in water) should be used with a SCR system and presumably in a SNCR system. Once again OUC believes that the permit should be silent on the specific technological requirements of meeting emission requirements. If use of aqueous ammonia is more effective, and can be stored, handled, and permitted appropriately, OUC should make the technical selection of an ammonia type. The discussion of aqueous ammonia should be eliminated.

Economic Impact Discussions

OUC believes that only site specific cost considerations should be included in the final determination. Costs presented in OUC's BACT analysis were prepared for Unit 2 based on site specific manufacturer quotations and cost factors. Comparison with other facilities cost estimates or generalized industry information is inappropriate. Should the EPA be inclined to correlate economics, site specific comparisons could then be made. OUC requests that economic comparisons made on a non-site specific basis be eliminated from the final determination.

Sulfur Dioxide Emissions

In page 13 of the preliminary determination the EPA recognized the potential eventuality of restricted low sulfur coal supplies and resultant price increases. This will require Unit 2, a source designed for 95 percent SO_2 removal, to burn a coal that directly competes with other sources implementing fuel switching to achieve compliance with the 1990 Clean Air Act Amendments. This scenario will likely lead to restricted supplies of low sulfur coal and increased price. Accordingly, OUC believes that language should be added to the SO_2 BACT determination to cap this potential economic burden.

Editorial Comments to be Addressed and Generalized Questions to be Answered

OUC requests that EPA address these editorial comments and answer the generalized questions to the preliminary determination and the draft permit modifications.

(1) On page 5 of the preliminary determination and page 1 of the draft permit modifications the Unit 1 allowable limit for SO_2 emissions should read "...and no less than 70% reduction (30-day rolling average)".

(2) On page 6 of the preliminary determination PM emissions should read "Particulate Matter" not "Total Suspended Particulate".

(3) On page 11 of the preliminary determination the control method for control of CO and VOC emissions should read "complete combustion of the coal consistent with NO_x emission limitations" not "the utilization of 'low-NO_x' burners".

(4) Based upon the discussion on page 14, third paragraph, EPA Region IV recognizes the probability of increased coal prices to OUC from restricted low sulfur coal supplies. Accordingly, will EPA Region IV work with OUC to derive language to be added to the SO_2 BACT determination to put a cap on the increased price so as to eliminate unjustified economic burden consistent with federal law?

(5) Page 16 notes the recent PC boiler NO_x determinations. In addition, please list the attainment status for these facilities with regard to nitrogen oxides and ozone (volatile organic compound) emissions.

(6) On page 19, third paragraph the unit designation should be Unit 2 instead of Unit 1.

(7) Page 19, last paragraph, and page 24, first paragraph discusses sulfur resistant catalysts. OUC is not aware of this product offering nor are recognized suppliers of SCR systems who have been contacted regarding this description. Please clarify or eliminate discussion.

(8) Page 19 or 20 of the preliminary determination did not describe how spent catalyst will be classified and how it will be disposed. This would appear to be a significant environmental impact. What provisions will be incorporated in the permit to allow for safe and effective spent catalyst disposal? OUC is concerned about the classification of this potentially hazardous waste product due to the concentration of catalyst poisons inherent with Eastern coals. Again this is but one factor in balancing the various environmental concerns.

(9) Either page 19 or 20 should also indicate the potential increase in sulfuric acid mist emissions as an environmental impact of SCR use.

(10) Either page 19 or 20 should address the potential hazards of handling and disposing of ammonia contaminated fly ash.

(11) Page 19 of the preliminary determination required corrections regarding annual NO_x and NH_3 emissions. Ammonia concentrations are expressed as volumetric wet, uncorrected.

(12) Page 22, paragraph 2 discusses that there have been recent reductions in catalyst costs. These reductions are reflected in the site specific economic analyses submitted by OUC for Unit 2. Either relate this comment specifically to Unit 2 or delete paragraph.

(13) Page 24 relates SCR experience from gas and oil fired combustion turbines and boilers. Based on the relative cleanliness of these fuels it is not believed that there is a close correlation for Unit 2. In addition,

worldwide experience consist of Japanese and European (German, Austrian, and Netherland) experience. Please clarify or eliminate discussion.

Conclusion

OUC in reviewing and commenting on the preliminary determination and draft permit modifications for Stanton Energy Center Unit 2 has evidenced its commitment to proceed by commenting and making constructive suggestions on various specific emissions and by supplying a markup in Appendix A with details of these comments and recommendations. This work product further demonstrates the flexibility authorized by the applicable federal law and the EPA preliminary determination and permit modification drafts with which OUC, in conjunction with EPA Region IV, New Source Review Section (RTP), and Florida DER can derive a landmark and precedent setting technology effective to attain and maintain all permitted emission levels. This regulatory cooperation contributes to the best interests of all concerned because it will result in reliable and effective control technologies which can be aggressively supported by EPA, the state of Florida, and OUC.

APPENDIX A

MARKUP OF

PRELIMINARY DETERMINATION AND TECHNICAL EVALUATION

AND

PROPOSED PERMIT MODIFICATIONS TO PSD-FL-084

PRELIMINARY DETERMINATION
AND
TECHNICAL EVALUATION

PERFORMED FOR ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER UNIT 2
ORANGE COUNTY, FLORIDA
PSD-FL-084

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
AIR, PESTICIDES AND TOXICS MANAGEMENT DIVISION

SEPTEMBER 1991

BACKGROUND

On June 10, 1982, the Orlando Utilities Commission (OUC) received a federal Prevention of Significant Deterioration (PSD) permit for their Curtis H. Stanton Energy Center Units 1 and 2. The permit was a "phased" construction permit issued by EPA Region IV pursuant to federal PSD regulations (40 CFR §52.21) which required that construction on Unit 1 begin no later than 18 months after the issuance of the permit (PSD-FL-084) and that construction of Unit 2 commence no later than 18 months after July 1, 1990. In addition, pursuant to 40 CFR §52.21(j)(4), the "determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of a multi-phased project." Should these commence construction deadlines not be met, the PSD permit would expire pursuant to the provisions of 40 CFR §52.21(r).

Construction commenced on Unit 1 on or about November 29, 1983, with operation commencing on or about May 12, 1987. After further assessment of power needs, however, OUC determined that the most advantageous time for Unit 2 to come on line would be 1997. Based on this revised estimate, OUC requested a meeting with EPA to discuss available options for the construction of Unit 2. In the meeting of February 23, 1989, EPA explained OUC's options for delaying the construction of Unit 2, based on 40 CFR §52.21(r)(2) and EPA's "Revised Draft Policy on Permit Modifications and Extensions" which was issued on July 5, 1985. These options were as follows:

1. Commence construction of Unit 2 prior to the January 1, 1992 deadline.

2. Complete and submit a new, separate permit application for the construction of Unit 2, letting the original construction authority for Unit 2 expire.

3. Request a permit modification in order to change the commence construction dates for Unit 2. Such a request must be made no later than six months prior to the expiration of the original permit.

OUC chose option number 3 - to request a permit modification for the commence construction dates. Since EPA had issued the original permit and since the State of Florida does not have the authority to modify EPA issued permits, the permit modification request has been processed by EPA. OUC submitted the modification request to EPA on March 18, 1991, thus meeting the requirement that such application be submitted to the reviewing agency no later than six months prior to the expiration of the permit.

The proposed modification consists of three parts:

1. The insertion of a commence construction date for Unit 2 of January 1, 1992. This would allow OUC until June 1, 1993, to commence construction on Unit 2 before the permit would expire.

2. A change to Specific Condition #1 of PSD-FL-084 to specify a heat input rate of 4,286 MMBTU/hr for Unit 2. The current condition specifies a heat input rate of 4,136 MMBTU/hr for each unit. This change will not affect the power generation of Unit 2 which will remain rated at 460 MW (gross) and 440 MW (net) as originally permitted.

3. A revised BACT determination for Unit 2 in fulfillment of Specific Condition #2 of PSD-FL-084 and federal PSD regulations. This determination will be completed for the pollutants PM, SO_2, NO_x, VOC, CO, and visible emissions.

I. Commence Construction Date

As discussed previously, later phase commence construction dates in a PSD permit cannot be automatically extended utilizing the provisions of 40 CFR §52.21(r). This section allows the Administrator to extend the initial 18-month commence construction period where such extension is determined to be justified. It does not, however, allow for automatic extensions for time periods between construction of approved phases of multi-phased projects.

While later phase commence construction dates cannot be changed by the granting of extensions, they can be changed through a permit modification, since the dates are part of the permit itself. The permit modification policy addresses this fact as follows:

> [t]he intent of 40 CFR §52.21(r)(2) is to establish an automatic 18-month expiration date for permits, with provisions for extending the expiration on a case-by-case basis. For phased projects with a single comprehensive permit, EPA presumed that commencement dates for each phase of the project, except the initial phase commencement date, would be incorporated into the permit. Therefore, initial phase commencement date changes would be handled with a 40 CFR §52.21(r)(2) extension, and subsequent phase commencement dates would be handled through permit changes. This acknowledges and preserves the validity and legality of the conditions specified in a permit.

Thus the appropriate mechanism for changing the commence construction date for Stanton Unit 2 would be permit modification. Such a modification is considered to be an Administrative change requiring public notice and comment.

In the specific case of OUC Stanton Unit 2, the Agency finds that the applicant's request for a change in the commence construction date is justified based upon a reevaluated schedule of need for power. In keeping with EPA's past policy of generally only allowing an 18-month extension of commence construction dates, it is appropriate to set the commence construction date for Unit 2 as January 1, 1992. Under PSD regulations, a continuous program of construction of Unit 2 must begin no later than 18 months after the commence construction date or the permit will automatically expire.

II. Modification to Heat Input Rate

The original PSD permit for Stanton Energy Center specified a heat input rate for each of the identical coal-fired boilers, Units 1 and 2, of 4,136 MMBTU/hr each. The resulting power generation from each boiler was calculated to be 460 MW (gross) and 440 MW (net). Through experience with Unit 1 and with boiler design improvements, the applicant has requested that the heat input rate to be specified for Unit 2 be changed to 4,286 MMBTU/hr. Since the BACT for Unit 2 is being reevaluated and will result in much lower emissions than originally projected for Unit 2, this change is not considered significant.

III. BEST AVAILABLE CONTROL TECHNOLOGY

On June 10, 1982, OUC was issued a federal PSD permit (PSD-FL-084) for Units 1 and 2 of the Curtis H. Stanton Energy Center. Best available control technology (BACT) was established for each of the 460 MW (gross) coal-fired units in PSD-FL-084 as follows:

POLLUTANT	CONTROL	ALLOWABLE LIMIT
PM	electrostatic precipitator	0.03 lb/MMBTU
SO_2	flue gas desulfurization	1.14 lb/MMBTU (3-hr avg.) and ~~90%~~ No less than 70% reduction (30-day rolling average)
NO_x	combustion controls	0.60 lb/MMBTU (30-day rolling average)
Visible Emissions		20% (6-min. avg), except for one 6-minute period per hour of not more than 27% opacity

In addition, since the PSD permit is a phased construction permit, Specific condition #2 contained a requirement that the adequacy of the BACT determination for Unit 2 be re-evaluated no later than 18 months prior to the commencement of construction of the unit.

The associated potential emissions for the two units combined was as follows in tons per year:

POLLUTANT	POTENTIAL EMISSIONS
PM	1,042
SO_2	39,606
NO_x	20,845
CO	1,737
VOC	17

a. Based on 4,136 X 10^6 BTU/hr heat input rate for each unit and 50 weeks per year operation.

b. Estimated 0.0005 lb VOC/MMBTU average emission rate.

These emissions were used in determining PSD applicability for the original permit and in the air quality analysis which demonstrated that the National Ambient Air Quality Standards would be protected while the PSD increments would not be exceeded.

BACT Determination Requested by the Applicant

OUC proposed a BACT determination consisting of an ESP to control particulates, flue-gas desulfurization (FGD) to control SO_2, and combustion controls for NO_x and CO.

The FGD system proposed by the applicant is a wet limestone scrubber designed to meet an emissions limit of 0.32 lb/MMBTU based upon a design coal sulfur content of 2.5%. The combustion control proposed by the applicant includes the use of "low-NO_x" burners to achieve a NO_x emission rate of 0.32 lb/MMBTU.

The applicant has requested BACT emissions rates on a pollutant-by-pollutant basis as shown below.

a. PM - (~~Total Suspended~~ Particulate MATTER)

0.020 lb/MMBTU

b. PM_{10}

0.020 lb/MMBTU

c. SO_2

0.32 lb/MMBTU (30-day rolling average)
0.67 lb/MMBTU (24-hour average)
0.85 lb/MMBTU (3-hour average)

d. NO_x

0.32 lb/MMBTU (30-day rolling average)

e. CO

0.15 lb/MMBTU

Trace constituents of the coal will be controlled through the combination of wet scrubbing (acid gases) and the ESP (particulates and heavy metals).

BACT DETERMINATION PROCEDURE:

Pursuant to federal regulations for Prevention of Significant Deterioration (PSD), 40 CFR §52.21, a new major stationary source "must apply best available control technology for each pollutant subject to regulation under the Act that it would have the potential to emit in significant amounts." Additionally, in relation to phased construction projects, paragraph (j)(4) states:

> "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable Stationary Source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

"Best available control technology" is defined in 40 CFR §52.21(b)(12) as:

> "an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques of control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a work standard infeasible, a design, equipment, work practice, operational standard, or a combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

In addition to the pollutants specifically subject to PSD review for a particular source, credence must be given to the control of any "unregulated" pollutants when determining best available control technology for an emissions unit. This policy, a result of the 1986 remand of a PSD permit for the North County Resource Recovery Facility by the Administrator of EPA, generally specifies that a more stringent emission limit for a "regulated" pollutant may be imposed if a reduction in "nonregulated" pollutants can be directly attributed to the control device selected as BACT for the "regulated" pollutants.

Emissions from fossil fuel-fired electric utility boilers can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the air emissions can be classified as follows:

- Combustion Products (Particulates and Heavy Metals) controlled generally by particulate control devices.
- By-products of incomplete combustion (CO, VOC, toxic organic compounds). Control is largely achieved by proper combustion techniques.
- Acid gases (SO_2, NO_x, HCl, F, H_2SO_4) Controlled generally by gaseous control devices.

BACT ANALYSIS

Combustion Products:

Under the review completed for PSD-FL-084, the combustion product for which a BACT analysis is required is particulate matter. Based on information now available, vendors can use either an electrostatic precipitator or fabric filter technology to achieve a level of 0.02 lb/MMBTU.

The "Standards of Performance for New Sources" (NSPS) which apply to Stanton Unit 2 are found in 40 CFR Part 60 Subpart Da. These standards establish a particulate emissions limit of 0.03 lb/MMBTU. Under Clean Air Act requirements, an applicable NSPS or NESHAP limit is the minimally acceptable level which can be selected as BACT. In addition, Subpart Da limits opacity to a maximum of 20%.

A review of the BACT/LAER Clearinghouse indicates that recent emissions limits on PM from pulverized coal (PC) boilers have been as follows:

SOURCE	LIMIT
Mecklenburg Cogeneration, VA	PM - 0.020 lb/MMBTU PM_{10} - 0.018 lb/MMBTU
Chambers Cogeneration, NJ (fabric filtration)	PM - 0.018 lb/MMBTU PM_{10} - 0.018 lb/MMBTU
Roanoke Valley Project, NC	PM - 0.020 lb/MMBTU PM_{10} - 0.018 lb/MMBTU

The applicant evaluated the use of fabric filtration as well as an ESP. In this evaluation, the feasibility of reaching an emission level of 0.012 lb/MMBTU on a continuous basis was assessed in relation to energy, economic, and environmental impacts. The base case selected by the applicant was the emissions level of 0.020 lb/MMBTU.

ESPs are historically the most widely used particulate control equipment for coal-fired power plants. The devices remove particulate from the flue gas stream by charging fly ash particles with very high dc voltage and then attracting these particles to oppositely charged collection plates. The collected particulate is then removed from the plates by periodic "rapping" which causes the particulate to drop into collection hoppers below the ESP.

Fabric Filtration, as the name implies, utilizes filter bags to "trap" particulate from the flue gas stream. As the flue gas passes through the filter bags, a "cake" of collected particulate builds up. This cake is necessary to increase the collection efficiency of the bags. The collected particulate can be removed in a variety of methods: reverse gas, shake-deflate, or pulse jet. The applicant, based on the size of the gas stream along with relative economics, chose the reverse gas method to be used in the BACT analysis.

<u>Energy Impacts</u>

According to the applicant, the use of an ESP would consume 85% more energy than a fabric filter designed to meet the same emission level. The applicant points out, however, that this energy consumption is equivalent to only 0.2 percent of the plant power output.

Economic Impacts

The applicant evaluated three scenarios:

1. The use of fabric filtration to meet an emissions level of 0.012 lb/MMBTU;

2. The use of an ESP to meet an emissions level of 0.020 lb/MMBTU; and,

3. The use of fabric filtration to meet an emissions level of 0.02 lb/MMBTU.

The factors which influence the cost of fabric filtration to meet the lowest limit include increased frequency of bag change-out and construction material of the bags. In addition, due to the nature of the device, baghouses are more susceptible to flue gas slip. Increased inspection and maintenance would be needed to ensure compliance with the low limit.

Factors influencing the cost of an ESP designed to meet a level of 0.020 lb/MMBTU include increased collection area, increased power usage, and increased inspection and maintenance over that required to achieve a level of 0.030 lb/MMBTU.

The applicant compared annualized costs for each of these control devices (Table 3.4-5 of Attachment 1) with the following results:

	1997 Total Levelized Annual Cost
FF - 0.012	$11.5 million
ESP - 0.020	$8.65 million
FF - 0.020	$8.77 million

The incremental cost in achieving the lowest limit was calculated to be $19,180 per additional ton of particulate removed.

Environmental Impacts

According to the applicant, ESPs are more effective than fabric filters at limiting the emissions of particulate sized less than 10 microns (PM_{10}). The National Ambient Air Quality Standard (NAAQS) for particulate matter is based on PM_{10}. Other environmental impacts include the fact that ESPs do not need to be "conditioned" over time to achieve the established removal efficiency. It is not necessary to allow time for a filter cake to build up in order to achieve the required removal efficiency.

Products of Incomplete Combustion

The products of incomplete combustion which are subject to a revised BACT analysis are carbon monoxide and VOCs. These pollutants are a direct relation to combustion conditions in the boiler.

Recent determinations for PC boilers include the following:

Mecklenburg Cogeneration, VA	CO - 0.020 lb/MMBTU VOC - 0.003 lb/MMBTU
Chambers Cogeneration, NJ	CO - 0.11 lb/MMBTU VOC - 0.0036 lb/MMBTU
Roanoke Valley Project, NC	CO - 0.20 lb/MMBTU VOC - 0.03 lb/MMBTU

There are no emissions standards in Subpart Da for either CO or VOC. The possible alternatives for reducing the pollutants are to change the boiler operating conditions or to install a catalytic conversion device to complete the oxidation of these pollutants. At this time, however, catalytic conversion of CO and VOC is not technically feasible for pulverized coal-fired boilers.

In regards to changing boiler operating conditions, the major impact would be environmental, i.e., decreasing CO and VOC could cause a resultant increase in NO_x emissions. The emissions levels proposed by the applicant, 0.15 lb/MMBTU for CO and 0.015 lb/MMBTU for VOCs is based ~~upon the utilization of "low-NO_x" burners.~~ ON COMPLETE COMBUSTION OF THE COAL CONSISTENT WITH NO_x EMISSION LIMITATIONS.

ACID GASES

Emissions of sulfur dioxide and oxides of nitrogen are known precursors to "acid rain," a major emphasis of the Clean Air Act Amendments of 1990. In addition, NO_x is a known precursor of ground level ozone, another major concern of the CAAA of 1990. These amendments have mandated reductions of 10 million tons per year of SO_2 and 2 million tons per year of NO_x from existing coal-fired facilities. Although both pollutants are "acid gases," their formation and control are fundamentally different, thus, they will be addressed separately.

<u>SO_2</u>

The formation of sulfur dioxide and its subsequent emissions are a direct result of the sulfur content of the fuel to be used. For Stanton Unit 2, the applicant has proposed a maximum sulfur content of 2.5% in the coal. This corresponds to an uncontrolled SO_2 emissions rate of 4.0 lb/MMBTU. Current practice for new coal-fired units is to add a flue-gas desulfurization (FGD) unit to lower SO_2 emissions.

40 CFR Part 60, Subpart Da sets an emissions standard of 1.2 lb/MMBTU and 90% removal; or 0.6 lb/MMBTU and 70% removal.

The current permit for Unit 1 contains a limit of 1.14 lb/MMBTU; however, due to the usage of low sulfur coal, Unit 1 has historically been able to achieve a level of 0.20 to 0.27 lb/MMBTU.

Recent determinations for PC boilers have been as follows:

Mecklenburg Cogeneration, VA	SO_2 - 0.17 lb/MMBTU (30-day average)
Chambers Cogeneration, NJ	SO_2 - 0.22 lb/MMBTU (60-min. average)
Roanoke Valley Project	SO_2 - 0.213 lb/MMBTU (30-day average)

The applicant has proposed the following emission levels for Unit 2 based on the use of 2.5% S coal and 92% removal of SO_2 on a continuous basis:

0.32 lb/MMBTU - 30 day rolling average

0.67 lb/MMBTU - 24 hr. average

0.85 lb/MMBTU - 3 hr. average

The control scenarios evaluated by the applicant include the use of a wet lime scrubber to meet a level of 0.24 lb/MMBTU; a wet limestone scrubber designed to meet a level of 0.32 lb/MMBTU; and, a lime spray dryer system designed to meet a level of 0.32 lb/MMBTU. The corresponding emissions of SO_2 with these scenarios was provided by the applicant as follows:

	Uncontrolled Emission (lb/MMBTU)	Controlled Emission Rate (lb/MMBTU)	Annual Emission (tons/year)
Wet lime	4.03	0.24	4,506
Wet limestone	4.03	0.32	6,008
Lime spray dryer	4.03	0.32	6,008

The air quality control systems evaluated by the applicant for SO_2 removal included particulate removal equipment since ESP's can be used with the first two options but a fabric filter must be used in conjunction with the lime spray dryer.

Energy Impacts

The energy impacts provided by the applicant for the different control systems included the energy requirements of the particulate control devices. As discussed in the analysis of the energy impacts for combustion products, the energy requirement for the ESP is 85% greater than for the fabric filter. As a result, the lime spray dryer system shows the lowest energy impacts - roughly half of the energy requirements for the wet limestone system. The energy requirements for the wet lime scrubber system is roughly 4/5 of the requirements for the wet limestone system. The use of a lower sulfur coal does not result in any significant energy impacts.

Economic Impacts

The economics related to establishing a BACT level for SO_2 are two-fold. First, there are the economics related to the capital and operating costs of specific control equipment. Secondly, there are the much more speculative economics related to the availability and projected future costs of low sulfur coal.

In the first case, comparative costs of the selected air quality control systems were provided by the applicant (Table 3.4-11 of Attachment 1). The results from this analysis were as follows:

Control Devices	1997 Total Levelized Annual Cost
Wet Lime AQCS	\$46,550,000
Wet Limestone AQCS	\$36,270,000
Wet Spray Dryer AQCS	\$52,440,000

The applicant calculated an incremental removal cost from 0.32 lb/MMBTU to 0.24 lb/MMBTU of \$6,780 per additional ton removed. The main differential between the control devices lies in the cost of the additives, where the cost of pebble lime (\$80/ton) is reported to be 10 times more expensive than the limestone (\$8/ton).

The economics of future coal supplies are much more difficult to ascertain. The applicant provided an analysis (Attachment 2) of projected future low sulfur coal supplies as well as speculation on how costs and supplies of Eastern U.S. low sulfur coal could be affected by future "fuel-switchers." Fuel-switchers refers to existing coal-fired facilities which will switch to lower sulfur content coals in order to meet requirements of Title IV (Acid Rain) of the CAAA of 1990.

at a reasonable cost

It is impossible for EPA to be a prognosticator of future coal market conditions and how changes of such conditions on a macro-economic scale would affect the ability of OUC to obtain low sulfur coal for Stanton Unit 2 at a reasonable cost. OUC is currently able to obtain 1% Sulfur coal for Unit 1. Recent BACT determinations have included the use of coal with sulfur content less than 2%. Considering BACT is determined on a case-by-case basis, that Stanton Unit 2 will not start-up until 1997, and that projections on future costs and supplies of low sulfur coals contain many factors that may or may not OCCUR ~~be altered~~ during the life of the plant, it must be concluded that the use of lower sulfur content coal is currently a viable alternative. HOWEVER, SHOULD THE COST OF LOW SULFUR COAL EXCEED REASONABLE BACT COST THRESHOLDS FOR SO_2 EMISSIONS CONTROL, THIS CONCLUSION MAY BE ALTERED TO ALLOW FOR COAL PROCUREMENT FLEXIBILITY. THE 1990 CLEAN AIR ACT AMENDMENTS ESTABLISH A PENALTY OF \$2,000 PER TON FOR EXCESS SO_2 EMISSIONS.

Environmental Impacts

The original PSD permit for Stanton Unit 2, allowed SO_2 emissions of 1.14 lb/MMBTU which equates to 4,715 lb/hr. or 19,803 TPY (based on 50 week per year operation). The SO_2 emission level proposed by the applicant, 0.32 lb/MMBTU, equates to 6008 TPY. An emission limit comparable to recent BACT determinations (0.21 lb/MMBTU) would equate to 3,942 TPY SO_2 emissions.

As discussed previously, SO_2 is a precursor to acid rain. In keeping with the congressional mandate for reductions in acid rain - causing pollutants, SO_2 emissions from new sources need to be minimized.

Also of considerable importance is the fact that the air quality modelling for Unit 2 indicated that 99% of the PSD Class II 24-hr. increment will be consumed.

Other Considerations

According to the applicant, FGD systems can only be expected to achieve a removal efficiency of roughly 3% less than the target rate on a continuous basis. This assertion is based on a statistical analysis of the operation of FGD systems (Attachment 2) and carries the premise that a target removal rate guaranteed by a vendor (i.e., 95%) can be met only under ideal conditions, not on a continuous basis. Using this assumption, the highest practical removal rate for a target rate of 95% would be 92%.

If this assumption is accepted, the maximum continuous removal rate for the control systems evaluated would be:

Wet lime AQCS	94%
Wet limestone AQCS	92%
Lime spray dryer	92%

Unit 2, like Unit 1, will be a "zero (water) discharge" unit. This means that the scrubber effluent will be recycled numerous times. While environmentally beneficial from a water standpoint, this recycling causes a buildup in the concentrations of trace constituents such as chlorides in the scrubber system. The applicant has presented data to demonstrate that this chloride buildup has slightly degraded the removal efficiency of Unit 1's scrubber over time.

Nitrogen Oxides

As discussed previously, NO_x is a precursor to acid rain as well as to ground level ozone. Subpart Da of the NSPS establishes a NO_x limit for utility boilers burning bituminous coal of 0.60 lb/MMBTU of heat input. This NSPS limit was established as BACT in PSD-FL-084; however, Stanton Unit 1 has historically been able to achieve a NO_x emission level of 0.4 to 0.5 lb/MMBTU.

The current status of control techniques for NO_x includes the use of combustion controls to limit the formation of NO_x as well as add-on controls to reduce NO_x emissions. These add-on controls include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

Recently permitted PC boilers have NO_x limits as follow:

Mecklenburg Cogeneration, VA low-NO_x	NO_x - 0.33 lb/MMBTU (30-day average)
Chambers Cogeneration, NJ SCR	NO_x - 0.17 lb/MMBTU (180 -min. average)
Roanoke Valley Project, NC low-NO_x burners	NO_x - 0.33 lb/MMBTU (30-day average)

NO_x AND OZONE ATTAINMENT STATUS?

Low NO_x Burners

The NO_x control system proposed by the applicant, the use of "low-NO_x" burners, is the result of efforts made by burner manufacturers to reduce the formation of fuel NO_x (the oxidation of fuel bound nitrogen). Over the last several years, burner manufacturers have been guaranteeing NO_x emissions levels of between 0.30 and 0.40 lb/MMBTU utilizing a "staged" combustion process for coal fired units.

While several recent permits have been issued for low-NO_x burners on coal-fired boilers, there has been some concern expressed as to whether these burners can meet manufacturers' claims on a continuous basis. In addition, test results have shown that the use of "staged" combustion will increase the fixed carbon content in the fly ash. This could present a problem to a source such as OUC which utilizes fly ash as a salable product. However, according to the applicant, estimates of carbon content in the fly ash for Stanton Unit 2 will not be high enough to cause the ash to fail to meet ASTM standards for mineral admixtures to concrete (C618-89a, Attachment 3).

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a flue gas cleaning method which utilizes the injection of ammonia into the flue gas in the presence of a catalyst to dissociate NO_x into N_2 and water. SCR was first developed in the U.S. in the late 1950's but received its first widespread use in power generation service in Japan in the 1970's. SCR has been utilized on gas, oil and coal-fired units. Likewise many West German coal-fired units (129 to date) have been retrofitted with SCR systems to minimize NO_x emissions. In the United States, one recent PSD permit was issued requiring SCR on a PC boiler (Chambers Cogeneration in New Jersey). NO COAL FIRED UNITS ARE CURRENTLY OPERATING WITH A SCR SYSTEM.

The major technical concerns in the past for the application of SCR to coal-fired service have revolved around potential ammonia slip; conversion of SO_2 to SO_3 by the catalysts and the resultant formation of ammonia salts; and poisoning of the catalyst by trace constituents of the coal.

Based upon operating experiences in Japan and Europe, catalysts manufacturers have developed "new generation" catalysts in an attempt to alleviate the problems mentioned above. The current status of ~~the "sulfur resistant"~~ new generation catalysts on the market is such that manufacturers will guarantee that SO_2 to SO_3 conversion will be limited to less than 1%. By limiting this conversion, the amount of SO_3 available to react with ammonia is minimized. The new catalysts are typically of the extruded "honeycomb" type which offer better reaction surface area than the older plate-type catalysts.

(REPRESENTING A POTENTIAL INCREASE IN SO_3, AND ULTIMATELY SULFURIC ACID MIST, OF 100 PERCENT)

The limiting of ammonia slip is also important for several reasons. First, ~~in conjunction with the sulfur-resistant catalysts,~~ low ammonia slip minimizes formation of ammonia salts or AMMONIUM BISULFATE DEPOSITS. Secondly, limiting ammonia slip reduces their potential for reaction with any trace quantities of chloride from the coal or SO_3 IN THE FLUE GAS which may result in an ammonium chloride plume. At ammonia slip levels typically found with SCR systems (i.e., around 5 ppm), this potential is ~~virtually~~ MINIMIZED. ~~eliminated.~~ The third major reason for limiting ammonia slip is to prevent contamination of the fly ash such that the fly ash remains a salable product. According to the applicant, ammonia slip must be limited to ~~below 5 ppm~~ APPROXIMATELY 2 PPM for coal with seven percent ash. The design coal, however, has ~~an~~ A MAXIMUM ash content of 12%, thus assuring that ~~the fly ash ammonia concentrations will be even less.~~ HIGHER AMMONIA SLIP CONCENTRATIONS COULD BE ACCOMODATED. ~~In any event, if the ash will be used in clinker production by the cement industry, the ammonia will be driven off in the clinker kiln.~~

Catalyst manufacturers are typically capable of providing a two-year catalyst guarantee.

indicated that US coal arsenic concentrations are significantly greater than worldwide averages. Arsenic is a significant catalyst poison.

~~In regards to~~ catalyst poisoning by trace constituents in U.S. coals, the applicant has ~~not provided any evidence that the projected constituents of the design coal are such that the projected catalyst life would be severely altered.~~ Over normal operation of the SCR system, catalyst will degrade or deactivate and require change-out. There is no indication that the design coal constituents would cause more frequent change-out of catalyst than would normally be guaranteed. Some or is representative of overseas experience.

Based on operating experiences with various overseas coals, ~~the availability of sulfur resistant catalysts~~ and the ability to minimize ammonia slip, it must be concluded that the use of SCR is technically feasible for Stanton Unit 2.

Selective non-catalytic reduction

relatively narrow

Selective non-catalytic reduction (SNCR) systems utilize either ammonia or urea as reagent to inject in the flue gas. There is a ~~very precise~~ temperature window in which the reagent must be injected. Additionally, since the reaction is not in the presence of a catalyst, a greater than stoichiometric amount of reagent is necessary to achieve desired NO_x removal efficiencies. This in turn can lead to ammonia slip much greater than from an SCR system. As discussed previously, elevated ammonia slip could result in excessive formation of ammonia salts, the formation of an ammonia chloride plume, or contamination of fly ash. To minimize ammonia slip it would be necessary to carefully limit the reagent/gas ratio which would probably result in ~~an effective~~ control efficiency of 30 to 40%. However, SNCR would not increase sulfuric acid mist emissions.

Current installations of SNCR include municipal waste incinerators and circulating fluidized bed (CFB) coal-fired boilers. The temperature profile of a CFB is much more stable than in a PC boiler and thus is conducive to establishing the proper temperature window to effectively operate SNCR. An additional concern is the possibility that an SNCR system may convert some of the NO_x emissions into N_2O.

ENERGY IMPACTS

The energy impacts of an SNCR system include the need for both steam and electrical energy. The applicant has estimated this need to be roughly 0.5 percent of the total plant power output.

The power needs for the SCR system was also estimated at 0.5 percent of the total plant power output. Also an energy consideration is the possible loss of boiler efficiency due to higher air heater exit temperatures related to the presence of SO_3 in the flue gas.

ENVIRONMENTAL IMPACTS

The area in which Stanton Energy Center is located is currently designated attainment for NO_x AND OZONE EMISSIONS. As stated previously, NO_x is a known precursor to both acid rain and ground level ozone.

The NO_x emissions of ~~Unit 1~~ UNIT 2 as compared to the evaluated alternatives is given below:

	EMISSIONS NO_x		EMISSIONS NH_3	
	lb/MMBTU	TPY	PPM*	TPY
Conventional Burner	0.60	11,263 ~~10,869~~	N/A	N/A
Low-NOx Burner	0.32	6,007 ~~5,934~~	N/A	N/A
LNB + SNCR (40% removal)	0.19	3,567 ~~3,604~~	20	476 ~~240~~
LNB + SNCR (30% removal)	0.22	4,130 ~~4,205~~	10	238 ~~120~~
LNB + SCR (70% removal)	0.17	3,191	5	119
	0.10	~~1,280~~ 1,877	5	~~68~~ 119

As discussed previously, ammonia slip from A SCR OR ~~the~~ SNCR system could POTENTIALLY result in the formation of ammonium chloride (visible plume) as well as increase the particulate loading due to formation of ammonia salts.

With the SCR system, ammonia slip related issues can be minimized. Systems manufacturers typically recommend special air heater designs which along with ~~the sulfur resistant catalyst and~~ minimum ammonia slip, serve to increase the reliability of the system. Japanese and

* PPM ARE ON A WET VOLUMETRIC BASIS, UNCORRECTED.

NONE OF THESE POTENTIAL NO_x LIMITATIONS WILL CAUSE AN EXCEEDANCE OF NATIONAL AMBIENT AIR QUALITY OR INCREMENT CONSUMPTION STANDARDS.

– HAZARDS OF HANDLING AND DISPOSAL OF AMMONIA CONTAMINATED FLY ASH?

– SPENT CATALYST DISPOSAL?

AS A RESULT OF THE SO_2 TO SO_3 CONVERSION POTENTIAL OF AN SCR CATALYST, MAXIMUM SULFURIC ACID MIST EMISSIONS COULD INCREASE TO AS MUCH AS 560 lb/h.

German experience has shown that cleaning ammonia salts from downstream components can be achieved with water washing and is usually limited to routine plant down-times, thus creating no impact on overall plant reliability. HOWEVER, THIS PRACTICE WILL CONTRIBUTE TO DIFFICULTIES ASSOCIATED WITH MAINTAINING ZERO WATER DISCHARGE STATUS FOR THIS SOURCE. The last environmental consideration is the storage of ammonia, a hazardous material. In order to alleviate safety concerns, many manufacturers recommend that aqueous ammonia be used rather than the much more volatile anhydrous ammonia. ~~The PSD permit for Chambers Cogeneration requires the use of aqueous ammonia (less than 28% solution in water).~~

Economic Impacts

The economic analyses provided by the applicant (attachments 1 and 4) were incremental costs analyses for SNCR and SCR as compared to their base case of low-NO_x burners. ~~In addition, cost analyses for Low-NO_x burners and SCR were obtained from EPA's Air and Energy Environmental Research Laboratory, based on cost models established by the Electric Power Research Institute (EPRI).~~

The analysis for SNCR provided by the applicant estimated an increase in capital costs of $14 million and $11 million for systems designed to meet 40% and 30% removal respectively. These costs result in estimated incremental cost effectiveness numbers of $2,700 per ton of NO_x removed (40%) and $3,100 per ton of NO_x removed (30%).

~~The cost estimation provided by the AEERL for the low-NO_x burner estimated capital costs to be increased by about $3.6 million over the cost of a conventional burner. The model assumed a NO_x reduction of 62%, resulting in a cost effectiveness number of $41.86 per ton of NO_x removed. The model also estimated a first year busbar cost of power at 0.009 mills/KWH and a levelized annual busbar cost of 0.11 mills/KWH.~~

~~The long-term NO_x emission limit established for Chambers Cogeneration is 0.17 lb/MMBTU; however, the system must be designed for 70% removal with 5 ppm ammonia slip - equivalent to 0.10 lb/MMBTU.~~

~~The cost estimate provided by AEERL considered two different scenarios:~~

~~1) 100% capacity and reduction to 0.17 lb/MMBTU;~~
~~2) 100% capacity and reduction to 0.10 lb/MMBTU;~~

COSTS NOT SITE SPECIFIC!

This model made estimates of total costs of the SCR plus the low NO_x burners. The results are as follows:

CASE	LEVELIZED ANNUAL REQUIREMENTS $	SYSTEM COST $/KW	FIRST YEAR BUSBAR MILLS/KWH	LEVELIZED ANNUAL BUSBAR MILLS/KWH	COST PER TON NO_x REMOVED $/TON
1	12,654,900	114.93	2.37	3.28	982.71
2	12,934,200	115.89	2.41	3.36	905.32

The cost analysis provided BY the applicant was an incremental analysis and evaluated two scenarios: 1) a two year catalyst life; and 2) a two to four year catalyst life: In each case, the amount of NO_x removed only considered reaching the level of 0.17 lb /MMBTU (i.e., a reduction of 47% of the NO_x available after application of low-NO_x burners). The analysis also included the cost of lost fly ash sales as well as the cost of landfilling the fly ash. ~~As discussed earlier, it is not readily apparent that fly ash sales will be affected; thus, the $1.4 million in levelized annual costs attributed to these activities should not be included in the analysis.~~

The resulting incremental cost effectiveness numbers for each scenario, considering ~~removals of 47% and 70%,~~ NOx EMISSIONS OF 0.17 lb/MBTU AND 0.10 lb/MBTU are as follows:

	LEVELIZED Total Annual Cost($)	NO_x Emissions Reduced (TPY)	LEVELIZED Incremental Cost ($/Ton)
2 yr Catalyst	19,130,000 ~~17,730,000~~	~~(47%) 2810~~ 2916 ~~(70%) 4160~~ 4130	6,793 ~~$6,309~~ 4,631 ~~$4,262~~
2/4 yr Catalyst	15,110,000 ~~13,710,000~~	~~(47%) 2810~~ 2916 ~~(70%) 4160~~ 4130	5,366 ~~$4,879~~ $3,659 ~~$3,295~~

In a paper presented at the 1991 Joint Symposium on stationary combustion NO_x Control by C.P. Robie, et. al., entitled "Technical Feasibility and Cost of SCR for U.S. Utility Application" (Attachment 5) , costs were estimated by EPRI for SCR being installed on new 500 MW coal-fired units. From this study, costs were expected to be in the range of $78 - 87/KW. The levelized cost was estimated to be in the range of 5.3 - 5.9 mills/KWH. The resulting cost efficiency was estimated to be $3,300 - $3,800/ton of NO_x removed. In addition, the report stated that the SCR capital cost in a new plant is substantially less than in a retrofit application.

The report also pointed out that reductions in catalyst unit costs have a large impact on the levelized costs. This mirrors a trend in the catalyst manufacturer industry in which catalyst costs have steadily decreased over time.

BACT Determination by EPA

Based on the preceding analyses, AND information provided by the applicant, ~~information obtained form AEERL?~~ review of the BACT/LAER Clearinghouse, review of papers presented at the 1991 Joint Symposium on Stationary Combustion NO_x Control, as well as review of permits for similar sources, the Agency has the following determination.

Particulate Matter

The use of an electrostatic precipitator (ESP) for the control of particulates is acceptable as BACT for Stanton Unit 2. The emission limit proposed by the applicant, 0.020 lb/MMBTU, is consistent with recent BACT determinations. Emission limits for Unit 2 are being established as follows:

PM (Particulate Matter):

0.020 lb/MMBTU

PM_{10}

0.020 lb/MMBTU

VE (Visible Emission)

Visible emissions from the stack shall not exceed 20% (6 minute average) except for one 6 minute period for hour of not more than 27% opacity.

PROCESS VAIRIABILITIES WILL RESULT IN GENERALLY LOWER

Sulfur Dioxide

The two major factors in SO_2 emissions are sulfur content of the coal and scrubber removal efficiency. The removal efficiency proposed by the applicant is 92% on a continuous basis utilizing a wet limestone scrubber. The vendor guarantee for this system is 95% removal; however, due to the fact that Stanton Unit 2 will be a "zero-discharge" unit, ~~some degradation of the~~ scrubber removal efficiency, ~~is expected.~~ The applicant has stated that the maximum ANNUAL expected removal rate will be 93.7%

AT REASONABLE COST

The second factor in the BACT determination for SO_2, sulfur content of the coal, must be evaluated based upon what is available today rather than on what may or may not be available in the future. OUC is currently able to obtain low sulfur coal (< 2% S) for Stanton Unit 1. Recent permits have been issued in Region IV on the basis of low sulfur coal. FDER is currently processing several permits in which coal-fired units will utilize low sulfur coal. In the current market, low sulfur coal is cheaper than high sulfur coal. It must be concluded that coal with a sulfur content less than that proposed by the applicant is readily available as of today. HOWEVER, SHOULD THE COST OF LOW SULFUR COAL EXCEED REASONABLE BACT COST THRESHOLDS THIS CONCLUSION MAY BE ALTERED TO ALLOW COAL PROCUREMENT FLEXABILITY.

The basis of the Agency's determination is the use of 2.0% sulfur coal along with a wet limestone scrubber with a continuous removal efficiency of 92%. Calculations of various removal efficiencies for different sulfur content coals (Attachment 7) yield an emission rate of 0.25 lb/MMBTU for 2.0% coal with 92% removal. An emission limit of 0.25 lb/MMBTU allows Stanton Unit 2 to utilize 2.5% sulfur coal when their scrubber removal efficiency approaches the expected ANNUAL AVERAGE maximum of 93.7%.

The SO_2 emission limits are being set for Stanton Unit 2 as follows:

0.25 lb/MMBTU (30-day rolling average)
0.67 lb/MMBTU (24 hour average)
0.85 lb/MMBTU (3 hour average)

X

Carbon Monoxide and Volatile Organic Compounds

The determination of BACT for the control of CO and VOCs is the use of combustion controls to minimize incomplete combustion. The resulting emissions rates for these pollutants are:

THIS BACT DETERMINATION MAY BE REEVALUATED SHOULD THE COST EFFECTIVENESS OF LOWER SULFUR COAL USE EXCEED A REASONABLE ECONOMIC COST TO OUC. FOR THE PURPOSES OF THIS EVALUATION, SCRUBBER PERFORMANCE WILL BE ASSUMED TO BE 92 PERCENT. IN ADDITION, SO_2 EMISSIONS WILL NOT BE ALLOWED TO EXCEED 0.32 lb/MBTU (30 DAY ROLLING AVERAGE). REEVALUATION OF THE LIMIT WILL NOT NECESSITATE EITHER NEW SOURCE REVIEW OR PSD REPERMITTING.

However, there remains uncertainty regarding the effects of poisoning agents in the flue gas from U.S. coal. Therefore, recognizing the potential problems associated with transfer of this technology, catalyst changeouts will be limited to no more than 50 percent of the initial catalyst charge within each ~~3~~ 5 year operating period. SHOULD CHANGEOUTS EXCEED THIS THRESHOLD AN APPROPRIATE NO_x EMISSION LIMIT WILL BE ESTABLISHED UP TO A MAXIMUM OF 0.22 lb/MBTU.

CO

0.15 lb/MMBTU

VOC

0.015 lb/MMBTU

Nitrogen Oxides

HAS RESULTED IN

IN JAPAN AND EUROPE

THIS OVERSEAS

Selective catalytic reduction (SCR) is an available technology which has been utilized on ~~combustion turbines, gas/oil-fired boilers, and~~ coal-fired boilers ~~world-wide~~. ~~Through several decades of~~ operating experience, SCR systems ~~have been developed~~ which, when properly designed and operated, can achieve high levels of NO_x reductions while minimizing ammonia slip and its associated problems. ~~As discussed in the analysis, catalysts are readily available which are sulfur resistant.~~

~~The basis for the BACT determination for NO_x emissions is the use of a SCR system designed to achieve a NO_x emission limit of 0.1 lb/MMBTU with ammonia slip limited to a maximum of 5 ppm before catalyst changeout.~~ Recognizing the importance of maintaining unit reliability, AND THE ENVIRONMENTALLY SOUND PRACTICE OF FLYASH REUSE AND ZERO WATER DISCHARGE the emission limit being established contains flexibility for the source in order to ensure that ammonia slip is minimized. To that end, the BACT NO_x emission limit for Unit 2 is being set as follows:

NO_x

0.17 lb/MMBTU (30-day rolling average)

CONSISTENT WITH THIS NO_x EMISSION LIMIT AMMONIA SLIP EMISSIONS WILL BE LIMITED TO 5ppmvw UNCORRECTED.

~~OUC Stanton Unit 2 is not scheduled to begin operation until 1997. In deference to the constant improvement in burner technologies and the development of other NO_x control technologies such as SNCR, the permit is being conditioned such that should OUC be able to demonstrate the capability of a technology other than SCR to be able to meet the established limit, the permit may be revised to incorporate the alternative technology.~~

SNCR IS A DEVELOPING TECHNOLOGY CAPABLE OF SIGNIFICANT NO_x EMISSIONS REDUCTION IN A COST EFFECTIVE FASHION.

PROPOSED PERMIT MODIFICATIONS TO PSD-FL-084

The Specific Conditions of federal permit PSD-FL-084 shall be modified as follows:

1. The proposed steam generating station shall be constructed and operated in accordance with the capabilities and specifications of the application including the 4,136 MMBTU/hr heat input rate for Unit 1 and the 4,286 MMBTU/hr heat input rate for Unit 2.

2. The emissions for Unit 1 shall not exceed the allowable emission limits listed in the following Table for SO_2, PM, NO_x and visible emissions:

<u>Allowable Emissions</u>

<u>Pollutant</u>	<u>lb/MMBTU</u>
PM	0.03
SO_2	1.14 (3-hr average) and NO LESS THAN 70 ~~90~~ percent reduction (30-day rolling average)
NO_x	0.60 (30-day rolling average)
Visible Emissions	20% (6-minute average), except for one 6-minute period per hour of not more than 27% opacity

The emissions for Unit 2 shall not exceed the allowable emission limits listed in the following Table for SO_2, PM, NO_x, CO, VOC, and visible emissions:

<u>Allowable Emissions</u>

<u>Pollutant</u>	<u>lb/MMBTU</u>
PM	0.02
PM_{10}	0.02
SO_2	0.25 (30-day rolling average) 0.67 (24-hour average) 0.85 (3-hour average)

Pollutant	lb/MMBTU
NO_x	0.17 (30-day rolling average)
CO	0.15
VOC	0.015
Visible Emissions	20% (6-minute average), except for one 6-minute period per hour of not more than 27% opacity.

Additional conditions are added to PSD-FL-084 as follows:

14. Compliance with the emission limits contained in Specific Condition #2 for Unit 2 shall be determined as follows:

PM Compliance with the particulate limits in this permit shall be demonstrated by emission tests conducted in accordance with the provisions of 40 CFR §60.48a(b).

SO_2 Compliance with the SO_2 emission limits and emission reduction requirements in this permit shall be demonstrated in accordance with the provisions of 40 CFR §60.48a(c).

NO_x Compliance with the NO_x emission limits in this permit shall be demonstrated in accordance with the provisions of 40 CFR §60.48a(d).

VOC Compliance with the volatile organic compound limit shall be determined in accordance with Reference Method 25 or 25A of 40 CFR Part 60, Appendix A.

CO Compliance with the carbon monoxide limit shall be determined in accordance with Reference Method 10A or 10B of 40 CFR Part 60, Appendix A.

VE Compliance with the opacity limit in this permit shall be demonstrated using EPA Reference Method 9 in accordance with the provisions of 40 CFR §60.11.

OR SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

15. The nitrogen oxide emissions from Unit 2 shall be controlled with low-NO_x burners, advanced combustion controls, ~~and~~ or Selective Catalytic Reduction (SCR) ~~technology~~ technologies. The system will be designed to achieve a NO_x emission rate of ~~less than 0.1~~ 0.17 lb/MMBTU.

16. Ammonia slip from VW UNCORRECTED the NO_x control system shall be limited to less than 5 ppm. ~~Aqueous ammonia (less than 28% solution in water) shall be used in the SCR system.~~

17. ~~In the event that alternative technologies capable of achieving the NO_x emission limit specified in Condition #2 for Unit 2 are developed prior to the operation of Unit 2, such technologies, after review and approval by the EPA Regional Office, may be implemented in place of the SCR system.~~

The General Conditions are hereby modified as follows:

9. All correspondence required to be submitted by this permit to the permitting agency shall be mailed to:

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division
U.S. EPA Region IV
345 Courtland Street, NE
Atlanta, Georgia 30365

Curtis H. Stanton Unit #2
DER Case No. PA 81-14/SA1
DOAH Case No. 91-1813EPP

10/10/91

SUPPLEMENTAL
CONDITIONS OF CERTIFICATION

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Curtis H. Stanton Unit #2
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SUPPLEMENTAL
CONDITIONS OF CERTIFICATION (COCs)

PART I

Administrative Conditions

I/I. ENTITLEMENT

Pursuant to s. 403.501-519, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Orlando Utilities Commission, Florida Municipal Power Agency, and Kissimmee Utility Authority as joint owner/operators of Curtis H. Stanton Unit #2.

I/II. SCOPE OF LICENSE

A. Certification has previously been issued by the Governor & Cabinet on 12/14/82 for the Stanton site, including associated transmission and rail spur lines, with subsequent modifications thereto. These Conditions of Certification address the supplementary changes related to the construction and operation of Unit #2 and associated transmission line and alternate access road (shown on Attachment I). Where these conditions supersede the original COC and modifications thereto, such COC are rendered void; otherwise, the original COC and modifications thereto remain in effect.

B. Unit #2 certification is limited to 516,200 KVA (465 MW at a 0.9 power factor) nameplate capacity.

I/III. JURISDICTIONAL AGENCIES

The following agencies are deemed to have jurisdictional interest in the certification, and thus regulatory authority over the development, construction, operation, and maintenance of the facility:

Department of Environmental Regulation (& Central District Office) [DER or DER/CDO]
South Florida Water Management District [SFWMD]
St. Johns River Water Management District [SJRWMD]
Game & Fresh Water Fish Commission [GFWFC]

Department of Natural Resources [DNR]
Department of Community Affairs [DCA]
Department of Transportation [DOT]
Orange County [OC]

I/IV. DEFINITIONS

A. Licensee: References herein to the "Licensee" apply to Orlando Utilities Commission, Florida Municipal Power Agency, and Kissimmee Utility Authority as joint owners of Stanton Unit #2, or to their successors or assigns. (See COC-I/V regarding transfer of certification).

B. Completeness/sufficiency: The term "complete" as used herein shall have the same meaning as contained in Chapter 120, F.S., not Chapter 403, F.S., i.e., a complete application shall also provide sufficient information for an agency to perform an analysis of compliance with the conditions of certification and applicable regulations. Where agency-recommended COCs have used the Ch. 403 FS term of "sufficient", that shall have the same meaning as the term "complete" as used herein.

C. Affected Agencies: References to the "affected agencies" apply to the jurisdictional agencies listed in COC-I/III.

D. Other terms: The meaning of terms not otherwise specified in A-C, as used herein, shall be governed by the definitions contained in Chapter 403, Florida Statutes and any regulations adopted pursuant thereto. In the event of any dispute over the meaning of a term in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation.

I/V. TRANSFER OF CERTIFICATION

If contractual rights, duties, or obligations are transferred under this Certification, notice of such transfer or assignment shall immediately be submitted to the Florida Department of Environmental Regulation and the Affected Agencies by the previous certification holder (Licensee) and the Assignee. Included in the notice shall be the identification of the entity responsible for compliance with the Certification. Any assignment or transfer shall carry with it the full responsibility for the limitations and conditions of this Certification.

I/VI. SEVERABILITY

The provisions of this certification are severable, and if any provision of this certification or the application of any provision of this certification to any circumstances, is held invalid, the application of such provisions to other circumstances and the remainder of the certification shall not be affected thereby.

I/VII. PROFESSIONAL CERTIFICATION

Where post-certification submittals are required by these conditions, drawings shall be signed and sealed by a Professional Engineer, or Professional Geologist, as applicable, registered in the State of Florida.

I/VIII. RIGHT OF ENTRY

The Licensee shall allow during operational or business hours the Secretary of the Florida Department of Environmental Regulation and/or authorized representatives, including personnel of the Affected Agencies, upon the presentation of appropriate credentials:

A. To have access during normal business hours (Mon.-Fri., 9:00 a.m. to 5:00 p.m.) to any records required to be kept under the conditions of this certification for examination and copying; and

B. To inspect and test any monitoring equipment or monitoring method required in this certification and to sample any discharge or pollutants; and

C. To assess any damage to the environment or violation of ambient standards; and

D. To have reasonable escorted access to the power plant site and any associated linear facilities to inspect and observe any activities associated with the construction, operation, maintenance, or monitoring of the proposed project in order to determine compliance with the conditions of this Certification. The Licensee shall not refuse immediate entry or access upon reasonable notice to any Affected Agency representative who requests entry for the purpose of the above noted inspections and presents appropriate credentials.

I/IX. DESIGN STANDARDS

The facility shall be constructed pursuant to the design standards presented in the application and any approved post-certification submittals, and shall be considered the minimum design standards for compliance.

I/X. LIABILITY

The Licensee shall hold and save the Affected Agencies harmless from any and all damages, claims, or liabilities which may arise by reason of the construction, operation, maintenance and/or use of any facility authorized by this Certification, to the extent allowed under Florida law.

I/XI. PROPERTY RIGHTS

The issuance of this certification does not convey any property rights in either real or personal property, nor any exclusive privileges, nor 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.

I/XII. COMPLIANCE

A. Compliance with Conditions

1. The Licensee shall at all times maintain in good working order and operate all treatment or control facilities or systems installed or used by the Licensee so as to achieve compliance with the terms and conditions of this certification. All discharges or emissions authorized herein shall be consistent with the terms and conditions of this certification. The discharge of any regulated pollutant not identified in the application, or more frequent than, or at a level in excess of that authorized herein, shall constitute a violation of the certification.

2. An environmental control program shall be established under the supervision of a qualified Environmental Engineer/Specialist to assure that all construction activities conform to applicable environmental regulations and the applicable Conditions of Certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during construction, the Licensee shall notify the DER Central District Office and Siting Coordination Office, as required in I/XII.B.

3. Any anticipated facility expansions beyond the certified initial nameplate capacity, production increases, or process modifications which may result in new, different, or increased discharges of pollutants, change in type of fuel, or

expansion in steam generation capacity shall be reported by submission of a modification petition pursuant to Chapter 403, Florida Statutes.

4. In the event of a malfunction of Unit #2's boiler's pollution control system, the licensee shall comply with 40 CFR 60.46a.

B. Non-compliance Notification

If, for any reason, the Licensee does not comply with or will be unable to comply with any limitation specified in this certification, the Licensee shall notify the Central District Office of the Department of Environmental Regulation by telephone within a working day that said non-compliance occurs and shall confirm this in writing within seventy-two (72) hours of becoming aware of such conditions, and shall supply the following information:

1. A description of the discharge and cause of noncompliance; and

2. The period of noncompliance, including exact dates and times; or if not corrected, the anticipated time the noncompliance is expected to continue, and steps being taken to reduce, eliminate and prevent recurrence of the noncomplying event.

C. Adverse Impact

The Licensee shall take all reasonable steps to minimize any adverse impact resulting from noncompliance with any limitation specified in this certification, including such accelerated or additional monitoring as necessary to determine the nature and impact of the noncomplying discharge.

I/XIII. POST-CERTIFICATION REVIEW

Further information may be required by these conditions for site-specific or more detailed review and approval to determine compliance with the conditions of certification. Compliance determinations of the Department and other reviewing agencies are be subject to review pursuant to Chapter 120, Florida Statutes.

A. In order to provide adequate lead time for review, such information, as developed, must be submitted for post-certification review at least 120 days prior to the intended commencement date of construction or operation of the feature undergoing review. Notification of the submittal of the information, and any determinations made pursuant to these COC, shall be provided to the DER Siting Coordination Office for record-keeping purposes.

B. Where such information is required, it shall be submitted to the agency(ies) named in the condition, which shall then have 30 days in which to determine the completeness (sufficiency) of the information. If a written request for additional information is not issued within the 30 day time period, the information will be presumed to be complete (sufficient).

C. Once the information has been determined complete (sufficient), the agency(ies) shall have 90 days, unless another time period has been specified herein, in which to make the determination regarding compliance.

I/XIV. COMMENCEMENT OF CONSTRUCTION

At least 30 days prior to the commencement of construction, the Licensee or Project Engineer shall notify the DER Siting Coordination Office, the DER Central District Office, and Affected Agencies of the construction start date. Quarterly construction status reports shall similarly be submitted by the Licensee beginning with the initial construction start date. The report shall be a short narrative describing the progress of construction.

I/XV. COMMENCEMENT OF OPERATION

At least 30 days prior to the commencement of operation, the Licensee or Project Engineer shall notify the DER Siting Coordination Office and Affected Agencies of the operation start date.

XVI. OPERATIONAL CONTINGENCY PLANS

A. Operating Procedures

The Licensee shall develop and make available for viewing at the Stanton site by the DER operating instructions for all aspects of the operations which are critical to keeping the facililty's pollution control equipment working properly and to keep the facility in compliance with air and water quality criteria.

B. Contingency Plans

The Licensee shall develop and make available for viewing at the Stanton site by the DER written contingency plans or procedures for the continued operation of the unit in event of pollution control equipment breakdown. stoppages which compromise the integrity of the operations must have appropriate contingency plans. Such contingency plans shall identify critical spare parts to be readily available.

C. Current Engineering Plans

For all pollution control and monitoring systems, the Licensee shall maintain a complete current set of as installed engineering plans, equipment data books, catalogs and documents in order to facilitate the smooth acquisition or fabrication of spare parts or mechanical modifications.

D. Application Modifications

The Licensee shall furnish appropriate modifications to drawings and plot plans submitted as part of the application.

I/XVII. REVOCATION OR SUSPENSION

This certification may be suspended or revoked for violations of any of its conditions pursuant to Section 403.512, Florida Statutes.

I/XVIII. CIVIL AND CRIMINAL LIABILITY

This certification does not relieve the Licensee from civil or criminal penalties for noncompliance with any conditions of this certification, applicable rules or regulations of the Department or Chapter 403, Florida Statutes, or regulations thereunder.

Subject to Section 403.511, Florida Statutes, this certification shall not preclude the institution of any legal action or relieve the Licensee from any responsibilities or penalties established pursuant to any other applicable State Statues, or regulations.

I/XIX. ENFORCEMENT

The Department of Environmental Regulation, as supported by the applicable Affected Agency, may take any and all lawful actions to enforce any condition of this Certification. Any agency which deems enforcement to be necessary shall notify the Secretary of DER of the proposed actions. The agency may seek modification of this Certification for any change in any activity resulting from enforcement of this Certification which change will have a duration longer than 60 days.

I/XX. FIVE-YEAR REVIEW

The certification shall be final unless revised, revoked, or suspended pursuant to law. At least every five years from the date of issuance of certification the Department shall review the project and these conditions of certification and propose any needed modifications.

I/XXI. MODIFICATION OF CONDITIONS

Pursuant to Subsection 403.516(1), F.S., the Board hereby delegates the authority to the Secretary to modify any condition of this certification not in conflict with condition of certification Part VII dealing with sampling, monitoring, reporting, specification of control equipment, related time schedules, emission limitations, variances or exceptions to water quality standards, transmission line, access road or pipeline construction, source of treated effluent cooling water, mitigation, transfer or assignment of the Certification or related federally delegated permits, or any special studies conducted, as necessary to attain the objectives of Chapter 403, Florida Statutes.

All other modifications to these conditions shall be made in accordance with Section 403.516, Florida Statutes.

Part II

Conditions Recommended by
the
Department of Environmental Regulation

II/I. AIR

The construction and operation of Unit 2 at Orlando Utilities Commission, Curtis H. Stanton Energy Center (CHSEC) steam electric power plant site shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, and 17-5, Florida Administrative Code except for NOx and SO_2 which shall be governed by 40 CFR Part 60 regarding startup, shutdown, and malfunction. In addition to the foregoing, the permittee shall comply with the following conditions of certification:

A. Emissions Limitations

1. The proposed steam generating station shall be constructed and operated in accordance with the capabilities and specifications of the application including the proposed 465 (gross) megawatt generating capacity and the 4286 MMBtu/hr heat input rate for each steam generator. Based on a maximum heat input of 4286 million Btu per hour, stack emissions from CHSEC Unit 2 shall not exceed the following when burning coal:

a. SO_2 - lb/million Btu heat input

30 - day rolling avereage	0.25
24 - hour emission rate	0.67
3 - hour emission rate	0.85

b. NOx - lb/million Btu heat input

30 day rolling average	0.17

c. PM/PM_{10} - lb/million Btu heat input

	lb/MBtu	lb/hr
PM	0.02	85.7
PM_{10}	0.02	85.7

d. CO - 0.15 lb/million Btu heat input, 643 lb/hour.

e. VOC - 0.015 lb/million Btu heat input, 64 lbs/hour.

f. H_2SO_4 - 0.033 lb/million Btu heat input 140 lb/hour.

g. Be - 5.2×10^{-6} lb/million Btu heat input, 0.022 lb/hour.

h. Hg - 1.1 x 10^{-5} lb/million Btu heat input, 0.046 lb/hour.

i. Pb - 1.5 x 10^{-4} lbs/million Btu heat input, 0.64 lb/hour.

j. Fluorides - 4.2 x 10^{-4} lb/million Btu heat input, 1.8 lbs/hour.

2. The height of the boiler exhaust stack for CHSEC Unit 2 shall not be less than 550 ft. above grade.

3. Particulate emissions from the coal, lime and limestone handling facilities:

a. All conveyors and conveyor transfer points will be enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer or emergency stockout, and the limestone stockout for which enclosure is operationally infeasible).

b. Inactive coal storage piles be shaped, compacted and oriented to minimize wind erosion.

c. Water sprays or chemical wetting agents and stabilizers will be applied to storage piles, handling equipment, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20%.

d. Limestone day silos and associated transfer points will be maintained at negative pressures during filling operations with the exhaust vented to a control system. Lime will be handled with a totally enclosed pneumatic system. Exhaust from the lime silos during filling will be vented to a collector system.

e. The fly ash handling system (including transfer and silo storage) will be totally enclosed and vented (including pneumatic system exhaust) through fabric filters; and

f. Any additional coal, lime, and limestone handling facilities for Stanton Unit 2 will be equipped with particulate control systems equivalent to those for Stanton Unit 1.

4. Particulate emissions from bag filter exhausts from the following facilities shall be limited to 0.02 gr/acf: coal, lime, limestone and flyash handling systems excluding those

facilities covered by 3.c above. A visible emission reading of 5% opacity or less may be used to established compliance with this emission limit. A visible emission reading greater than 5% opacity will not create a presumption that the 0.02 gr/acf emission limit is being violated. However, a visible emission reading greater than 5% opacity will require the permittee to perform a stacktest for particulate emissions, as set forth in Condition I.C.

5. Compliance with opacity limits of the facilities listed in Condition II/I.A. will be determined by EPA referenced method 9 (Appendix A, 40 CFR 60).

6. Construction shall reasonably conform to the plans and schedule given in the application.

7. The permittee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the DER Central District office in Orlando.

8. Reasonable precautions to prevent fugitive particulate emissions during construction shall be to coat the roads and construction sites used by contractors, regrass or water areas of disturbed soils.

9. Coal shall not be burned in the unit unless the electrostatic precipitator and limestone scrubber and other air pollution control devices are operating as designed except as provided under 40 CFR Part 60, Subpart Da.

10. The fuel oil to be fired in Stanton Unit 2 and the auxiliary boiler shall be "new oil" which means an oil which has been refined from crude oil and has not been used. On-site generated lubricating oil and used fuel oil which meets the requirements of 40 CFR 266.40 may also be burned. The quality of the No. 2 fuel oil used by the auxiliary boiler shall not contain more than 0.5% sulfur by weight and cause the allowable emission limits listed in the following table to be exceeded. Such emissions may be calculated in accordance with AP-42.

Allowable Emission Limits

Pollutant	lb/MMBtu
PM	0.015
SO_2	0.51
NO_x	0.16
Visible emissions	Maximum 20% Opacity

11. The flue gas scrubber shall be put into service during normal operational startup, and shut down when No. 6 fuel oil is being burned. The No. 6 fuel oil shall not contain more than 1.5% sulfur by weight.

12. No fraction of flue gas shall be allowed to bypass the FGD system to reheat the gases exiting from the FGD system, except that bypass shall be allowed during start up or shut down.

13. All fuel oil and coal shipments received shall have an analysis for sulfur content, ash content, and heating value either documented by supplier or determined by analysis. Records of all the analyses shall be kept for public inspection for a minimum of two years after the data is recorded by OUC.

14. Within 90 days of commencement of operations, the applicant will determine and submit to FDER the pH level range in the scrubber reaction tank that correlates with the specified limits for SO_2 in the flue gas. Moreover, the applicant is required to operate a continuous pH meter equipped with an upset alarm to ensure that the operator becomes aware when the pH level of the scrubber reaction tank falls out of this range. The pH monitor can also act as a backup in the event of malfunction of the continuous SO_2 monitor. The value of the scrubber pH may be revised at a later date provided notification to FDER is made demonstrating the emission limit is met. Further, if compliance data show that higher FGD performance is necessary to maintain the emissions limit, a different pH value will be determined and maintained.

15. The applicant will comply with all requirements and provisions of the New Source Performance standard for electric utility steam generating units (40 CFR 60 Part Da).

16. The Licensee shall submit to the Department at least 120 days prior to start of construction of the NOx control system, copies of technical data pertaining to the selected NOx control system. These data, if applicable to the technology chosen by the Licensee, should include, but not be limited to design efficiency, guaranteed efficiency, emission rates, flow rates, reagent injection rates, or types of catalysts. The Department may, upon review of these data, disapprove the use of any such device or system if the Department determines the selected control device or system to be inadequate to meet the emission limits specified in 1.b. above. such disapproval shall be issued within 90 days or receipt of the technical data.

B. Air Monitoring Program

1. A flue gas oxygen meter shall be installed for Stanton Unit 2 to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. The flue gas oxygen monitor shall be calibrated and operated according to manufacturer's established procedures as approved by DER. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" may be used as a guide.

2. The permittee shall install and operate continuous monitoring devices for Stanton Unit 2 main boiler exhaust for sulfur dioxide, nitrogen dioxide and opacity. The monitoring devices shall meet the applicable requirements of Section 17-2.710, F.A.C., and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the FGD scrubber.

3. The permittee shall operate one continuous ambient monitoring device for sulfur dioxide in accordance with DER quality control procedures and EPA reference methods in 40 CFR, Part 53, and one ambient monitoring devices for PM_{10}, and one continuous NO_x monitor. The monitoring devices shall be specifically located at a location approved by the Department. The frequency of operation of the particulate monitor shall be every six days commencing as specified by the Department. During construction and operation the existing meteorological station will be operated and data reported with the ambient data.

4. The permittee shall maintain a daily log of the amounts and types of fuel used. The log shall be kept for inspection for at least two years after the data is recorded. Fuel analysis data including sulfur content, ash content and heating values shall be determined on an as-received basis and kept for two years.

5. The permittee shall provide stack sampling facilities as required by Rule 17-2.700(4) F.A.C.

6. The ambient monitoring program shall begin at least one year prior to initial start up of Unit 2 and shall continue for at least one year of commercial operation. The Department and the permittee shall review the results of the monitoring program annually and determine the necessity for the continuation of or modifications to the monitoring program.

C. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which Unit 2 will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct performance tests for particulates, SO_2, NO_x, and visible emissions during normal operations near (±10%) 4286 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a and 48a.

2. Compliance with emission limitation standards mentioned in specific Condition II/I.A. shall be demonstrated during initial performance tests using appropriate EPA Methods, as 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), or any method as proposed by the Applicant and approved by Department, in accordance with F.A.C. Rule 17-2.700.

EPA Method	For Determination of
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3	Gas analysis when needed for calculation of molecular weight or percent 0_2.
4	Moisture content when converting stack volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM_{10} emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, 7C, or 19	Nitrogen oxide emissions from stationary sources.

9	Visible emission determination of opacity.
-	At least three one hour runs to be conducted simultaneously with particulate testing for the emissions from dry scrubber/baghouse, and ash handling building baghouse.
-	At least one lime truck unloading into the lime silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12 or 101A	Lead concentration from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18, 25, or	Volatile organic compounds concentration.
101A or 108	Mercury emissions.
104	Beryllium emission rate and associated moisture content.

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3. The permittee shall provide 30 days written notice of the performance tests for continuous emission monitors or 10 working days written notice for stack tests in order to afford the Department the opportunity to have an observer present.

4. Stack tests for particulates NO_x and SO_2 and visible emissions shall be performed annually in accordance with Conditions C.2, and 3 above.

D. Reporting

1. For Stanton Unit 2, a summary in the EPA format of stack continuous monitoring data, fuel usage and fuel analysis data shall be reported to the Department's Central Florida District Office and to the Orange County Environmental Protection Department on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Section 60.7, and 60.49a and in accordance with Section 17-2.710(2), F.A.C.

2. Utilizing the SAROAD or other format approved in writing by the Department, ambient air monitoring data shall be reported to the Bureau of Air Quality Management of the Department quarterly. Such reports shall be due within 45 days following the quarterly reporting period. Reporting and monitoring shall be in conformance with 40 CFR Parts 53 and 58.

3. Beginning one month after certification, the permittee shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of air pollution control equipment. All reports and information required to be submitted under this condition shall be submitted to the Siting Coordination Office, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida, 32301.

E. Malfunction or Shutdown

In the event of a prolonged (thirty days or more) equipment malfunction or shutdown of air pollution control equipment, operation may be allowed to resume or continue to take place under appropriate Department order, provided that the Licensee demonstrates such operation will be in compliance with all applicable ambient air quality standards and PSD increments. During such malfunction or shutdown, the operation of Stanton Unit 2 shall comply with all other requirements of this certification and all applicable state and federal emission standards not affected by the malfunction or shutdown which is the subject of the Department's order. Exceedances produced by operational conditions for more than two hours due to upsets in air pollution control systems as a result of start-up, shutdown, or malfunctions as defined by 40 CFR 60 shall be reported as specified in Conditions I/XII. Identified operational malfunctions which do not stop operation but may prevent compliance with emission limitations shall be reported to DER as specified in Condition I/XII.

F. Open Burning

Open burning in connection with initial land clearing shall be in accordance with Chapter 17-256, F.A.C., Chapter 5I-2, F.A.C., Uniform Fire Code Section 33.101 Addendum, and any other applicable County regulation.

Any burning of construction generated material, after initial land clearing that is allowed to be burned in accordance with Chapter 17-256, F.A.C., shall be approved by the DER Central Florida District Office in conjunction with the Division of Forestry and any other County regulations that may apply. Burning shall not occur unless approved by the jurisdictional agency or if the Department or the Division of Forestry has issued a ban on burning due to fire safety conditions or due to air pollution conditions.

G. Federal Annual Operating Permits and Fees

1. DER Responsibilities

The Department of Environmental Regulation shall implement the provisions of Title V of the 1990 Clean Air Act for the Stanton 2 by developing Conditons of Certification requiring submission of annual operating permit information and annual pollutant emission fees in accordance with Federal Law and Federal Regulations.

2. OUC Responsibilities

OUC shall submit the appropriate annual operating permit application information as well as the appropriate annual pollutant emission fees as required by Federal Law to the Department as specified in Condition 3. below.

3. Annual Operating "Permit" Application and Fee (Reserved)

II/II. WETLANDS RESOURCE MANAGEMENT

1. The proposed transmission line from the Stanton Energy Center to the Mud Lake transmission line and the proposed alternate access road to the Stanton Energy Center from the south shall be routed as shown in the supplemental application. Prior to construction, the permittee shall submit drawings on 8.5" by 11" paper showing the final design, including plan view and cross-sections for each area of filling or clearing in wetlands. The drawings shall show the existing and proposed ground elevations and all existing and proposed structure locations, sizes and invert elevations.