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Orlando Utilities Commission
Stanton Amendments

B&V Project 143799
August 31, 2007

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BUREAU OF AIR REGULATION

Mr. Scott M. Sheplak, P.E.
Bureau of Air Regulation
Florida Department of Environmental Protection
Mail Station #5505
2600 Blair Stone Road
Tallahassee, FL 32399

Subject: OUC Curtis Stanton Energy Center PA81-14
Project Number 0950137-012-AC
Emissions Reductions and Facility Operations Improvement Projects

Dear Mr. Sheplak:

Black & Veatch, on behalf of the Orlando Utilities Commission (OUC), is providing information in response to your Request for Additional Information (RAI) dated March 7, 2007. The request addressed the air construction permit application received by your Department on February 6, 2007. On June 8, 2007, Black & Veatch, on behalf of OUC, requested by electronic mail to Mr. Al Linero a ninety (90) day extension of time to respond to the RAI. In your letter to Ms. Denise Stalls of OUC dated June 14, 2007, the extension of time to September 3, 2007 was granted.

Your RAI letter of March 7 contained twelve (12) questions, most of which were answered in a subsequent correspondence sent to you on August 9, 2007. The enclosed submittal completes the response to Questions 1, 2, 4, and 7. All of the aforementioned correspondence is attached for your reference and convenience.

This submittal includes:

- Updated response to Questions 4 and 7 in the RAI dated March 7, 2007.
- Results of a Best Available Control Technology analysis.
- Results of an Air Quality Impact Analysis and Additional Impact Analysis.
- Revised pages 6, 11, 22, and 23 from the air construction permit application submitted on February 6, 2007.
- Certification page signed and sealed by a professional engineer (Question 1).
- Electronic files of the entire submittal, including dispersion modeling files, on a compact disk (Question 2).

The compact disk (CD) contains all of the files included this submittal plus pertinent files from the February submittal. Two of the files contained in that early submittal are not relevant to this one. One, the railroad siding amendment request, does not have any air quality implications. The other, the railcar maintenance facility amendment request, has been formally withdrawn from consideration.

Here is a list of the files and file names contained on the enclosed CD:

- (File) 070831 Response to 070307 RAI.pdf
- (File) 070809 Response to 070307 RAI.pdf
- (File) 070614 Grant of Extension from Sheplak.pdf
- (File) 070307 RAI from Sheplak.pdf
- (Folder with 2 files) Request 10 – Headwaters-Flyash Blending (2-5-07)
- (Folder with 6 files) Request 12 – Air Permit Application (2-5-07)

We believe this submittal represents an adequate response to the four questions cited above. However, should you or others at the agency require additional information, please don't hesitate to contact us by calling me at (913) 458-7563 or Denise Stalls of OUC at (407) 737-4236.

Thank you for continuing to work with us in resolving these technical and permitting issues.

Sincerely,

Mike Soltys

Mike Soltys
Site Certification Coordinator

Enclosures

cc: Al Linero, FDEP
Mike Halpin, FDEP
Ann Seiler, FDEP
Denise Stalls, OUC
Lorraine Guise, OUC
Louis Brown, OUC
Myron Rollins, Black & Veatch
Brian O'Neal, Black & Veatch
John Davisson, Black & Veatch
Salvatore Falcone, Black & Veatch

Question 4: Table 3-1 on page 3-2 lists the significant emission rates (SERs) and Section 3.3 discusses emission changes however, an actual estimate of emission changes was not provided. Provide an estimate of emissions after the Project to compare the estimated emissions to the SERs in order to show that PSD will not be triggered. Prepare a table showing the estimated emissions compared to the SERs.

__Response:__ On December 31, 2002, the United States Environmental Projection Agency (USEPA) substantially reformed the Prevention of Significant Deterioration (PSD) program, including the manner in which a project's emissions increase is determined. Florida amended its rules, effective February 2006, to address the USEPA PSD reforms.

In terms of PSD applicability, a project at an existing major source will not be subject to PSD review if it does not result in a significant emissions increase. In general, a project's emissions increase is determined as the difference between its baseline actual emissions (BAE) and its future projected actual emissions (PAE). One is also allowed to consider excludable emissions (EE) when making this comparison.

The starting point for this type of analysis at the Stanton Energy Center is the determination of the baseline actual emissions (BAE) for Units 1 and 2 combined. For this analysis, the BAE emissions were determined using historical emissions data and the methodology set forth in the current PSD regulations. The historical emissions data used were the continuous emissions monitoring system (CEMS) data for SO_2 and NO_x emissions found on the USEPA Clean Air Markets web site and in the annual operating report (AOR) for all other pollutants. The BAE period is chosen on a pollutant by pollutant basis as the 24-month period within the five year look-back period that has the highest emissions of that pollutant based on historical emissions data. The BAE period can be different for each pollutant but must be the same for both units for each individual pollutant. The period calendar years 2004 and 2005 were used as the BAE period for this discussion. In general, this period saw a relatively high level of operation for both Unit 1 and Unit 2. Table 1 shows the BAE period, Unit 1 BAE emissions, Unit 2 BAE emissions, and the combined BAE emissions for each pollutant.

Table 1 BAE Emissions								
Pollutant	BAE Period	Unit 1 BAE Heat Input (mmBtu/yr)	Unit 1 BAE Emission Level (tpy)	Unit 1 BAE Emission Level (lb/mmBtu)	Unit 2 BAE Heat Input (mmBtu/yr)	Unit 2 BAE Emission Level (tpy)	Unit 2 BAE Emission Level (lb/mmBtu)	Combined BAE Emission Levels (tpy)
NO_x	Jan 2004 – Dec 2005	32,489,743	6,696.4	0.412	31,989,507	2,629.0	0.164	9325.4
VOC	Jan 2004 - Dec 2005	32,489,743	46.60	0.0029	31,989,507	44.2	0.0028	90.8
PM_{10}	Jan 2004 – Dec 2005	32,489,743	51.9	0.0032	31,989,507	94.4	0.0059	146.3
PM	Jan 2004 – Dec 2005	32,489,743	53.1	0.0033	31,989,507	95.4	0.0060	148.5
SO_2	Jan 2004 – Dec 2005	32,489,743	5,166.2	0.318	31,989,507	2,639.8	0.165	7,806.0
CO	Jan 2004 – Dec 2005	32,489,743	361.0	0.022	31,989,507	392.1	0.025	753.1

Once the BAE is established, the next step is to determine the EE based on the projected operation of each unit without the project. Essentially, the rules allow one to exclude from the emissions increase calculation those emission increases that would have occurred without the project. As will be discussed shortly, the EE can be considered an adjusted BAE and is subtracted from the projected actual emissions (PAE) to determine the project emission increases. As a basis for determining the EE it is assumed that without the project, the maximum operation of either unit would at least be as great as the maximum 12-month period during the look-back period. Therefore, for each unit the CEMS data was used to determine the maximum expected annual heat input to each unit. The maximum projected annual heat input rates are 37,316,142 mmBtu and 34,881,583 mmBtu for Unit 1 and Unit 2, respectively. These heat input rates, along with the respective BAE lb/mmBtu emissions level for each pollutant were used to determine the EE levels, as shown in Table 2.

Table 2 EE			
Pollutant	Unit 1 EE Emission Level (tpy)	Unit 2 EE Emission Level (tpy)	Combined EE Emission Levels (tpy)
NO_x	7,687.1	2,860.3	8,300*
VOC	54.1	48.8	102.9
PM_{10}	59.7	102.9	162.6
PM	61.6	104.6	166.2
SO_2	5,933.3	2,877.7	8,811.0
CO	410.5	436.0	846.5

Notes:
* The NOx EE is set equal to the permit limit taken as part of the netting analysis for Stanton B.

Once the BAE and EE are established, the next step is to determine the PAE values. In determining the PAE for each unit, one needs to differentiate between the projected increases due to natural demand growth versus the increases due to the project. But because the project is not expected to increase demand growth, the operation of the units either with or without the project is expected to be the same. Therefore, the projected unit operation is the same as that used in the EE determination, 37,316,142 mmBtu and 34,881,583 mmBtu for Unit 1 and Unit 2, respectively. Also, since there is no short-term hourly or lb/mmBtu type of emissions increase for NO_x, VOC, PM/PM_{10}, or SO_2 associated with the project, the unit's calculated PAE levels shown in Table 3 are identical to the EE levels. The exception here is CO.

As discussed in the February 2007 application, historical emissions of CO from Units 1 and 2 have been based on the appropriate AP-42 emission factor. This emission factor is on a lb/ton basis and its use results in a relatively low estimated CO emissions rate. While it is dependent on the coal heating value, using the AP-42 emission factor of 0.5 lb/ton with a 12,500 Btu/lb coal results in an estimated CO emission rate of 0.02 lb/mmBtu. This is similar to the lb/mmBtu values for CO presented in Table 1. Because emissions of CO data from conventional power plants are much less reliable than other pollutants such as NO_x and SO_2, in going forward with the projection of emissions OUC is using the vendor guarantee emission rates for CO after installation of the Low NO_x Burner/Overfire Air (LNB/OFA) systems. Specifically, the guarantees are Unit 1 at 0.18 lb/mmBtu and Unit 2 at 0.15 lb/mmBtu on a 30-day rolling average basis.

Table 3 PAE			
Pollutant	Unit 1 PAE Emission Level (tpy)	Unit 2 PAE Emission Level (tpy)	Combined PAE Emission Levels (tpy)
NO_x	7.687.1	2.860.2	8,300*
VOC	54.1	48.8	102.9
PM_{10}	59.7	102.9	162.6
PM	61.6	104.6	166.2
SO_2	5.933.3	2,877.7	8,811.0
CO**	3.358.5	2,616.1	5,974.6

Notes:
* The NOx PAE is set equal to the permit limit taken as part of the netting analysis for Stanton B.
** CO PAE is based on vendor guarantee of CO emissions post installation of the LNB/OFA systems on Units 1 and 2. Specifically, Unit 1 at 0.18 lb/mmBtu and Unit 2 at 0.15 lb/mmBtu.

Once the BAE, EE, and PAE values are determined, the next step is to run the calculations to determine the emissions increase to compare with the PSD SER levels.

Table 4 PAE to EE Comparison						
Pollutant	Combined BAE Emission Levels (tpy)	Combined PAE Emission Levels (tpy)	Combined EE Levels (tpy)	Project Emissions Increase (tpy)	PSD SER (tpy)	PSD Major Modification (Yes/No)
NO_x	9325.4	8,300*	8,300*	-1025.4	40	No
VOC	90.8	102.9	102.9	0	40	No
PM_{10}	146.3	162.6	162.6	0	15	No
PM	148.5	166.2	166.2	0	25	No
SO_2	7.806.0	8,811.0	8,811.0	0	40	No
CO	753.1	5,974.6	846.5	5,128.1	100	Yes

Notes:
* The NOx PAE and EE are set equal to the permit limit taken as part of the netting analysis for Stanton B.

Note that a primary focus of the modifications requested with this application (including the February 2007 submittal) are to reduce NO_x and SO_2 emissions and that is reflected somewhat in the decrease in NO_x emissions shown in Table 4. However, because the purpose of this analysis is simply to demonstrate that emission increases for NO_x, VOC, PM/PM_{10}, and SO_2 will be below the SERs and thus not be considered a major modification for PSD, the full effect of NO_x and SO_2 reductions are not built into this analysis. The expected project benefits to future NO_x and SO_2 emissions are covered in more detail in responses to items 5, 7, and 8 of the request for additional information submitted to the Department on August 9, 2007.

As discussed previously, because of the historically low CO emissions reporting that went into creating the BAE and the EE and the use of vendor guarantees for CO emissions after installation of the LNB/OFA systems in determining the PAE, the resulting emissions increase for CO illustrated in Table 4 is greater than 100 tpy (the PSD SER for CO). As such, CO is subject to the PSD permitting process for the modification. OUC is submitting via this response a request for a PSD permit modification for CO. The necessary components of the PSD application for CO, including the BACT analysis, air dispersion modeling analysis, additional impacts analysis, and updated FDEP forms (from the February 2007 application) are contained in Attachments 1, 2, and 3.

These additional pieces of information, along with this response, the responses submitted to the Department on August 9, 2007, and the original application submitted in February comprise a complete application submittal for your review and approval.

Attachment 1

BACT Analysis

1.0 Best Available Control Technology (BACT) Analysis

1.1 Introduction and Methodology

As required under the NSR/PSD regulations, the BACT analysis presented herein employed a top-down, five-step analysis to determine the appropriate emission control technologies and emissions limitations for the Project. The BACT analysis was conducted for Units 1 and 2 and limited to the pollutant CO as that is the subject of this PSD application. The BACT analysis was conducted in accordance with the United States Environmental Protection Agency's (USEPA's) recommended methodology:

- Step 1--Identify All Control Technologies.
- Step 2--Eliminate Technically Infeasible Options.
- Step 3--Rank Remaining Control Technologies by Control Effectiveness.
- Step 4--Evaluate Most Effective Controls.
- Step 5--Select BACT.

Step 1--Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options for the emission unit in question. The available control options consist of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The available control technologies and techniques include lower emitting processes, practices, and post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques that are classified as pre-combustion controls. Post-combustion controls are add-on controls for the pollutant being controlled.

Step 2--Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to identify the technical feasibility of the control options identified in Step 1, which are evaluated with respect to source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined by a clearly documented case of a control option that has technical difficulties which would preclude its successful use because of physical, chemical, and engineering principles. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size under review (demonstrated). If the control option cannot be demonstrated, the analysis gets more involved. When determining if a control option has been demonstrated, two key concepts need to be analyzed. The first concept, availability, is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, applicability, is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, a commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or one with similar gas stream characteristics.

Step 3–Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. The list to determine the rankings of the control technologies should include the following: control effectiveness (percent of pollutant removed), expected emission rate (tons per year), expected emission reduction (tons per year), energy impacts (Btu, kWh), environmental impacts (other media and the emissions of toxic and hazardous air emissions), and economic impacts (total cost-effectiveness and incremental cost-effectiveness). However, if the BACT analysis proposes the top control alternative, from an emission reduction standpoint, there would be no need to provide cost and other detailed information in regard to other control options that would provide less control.

Step 4–Evaluate Most Effective Controls

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as "Impact Analysis." The following impact analyses are performed:

- Energy evaluation of alternatives.
- Environmental evaluation of alternatives.
- Economic evaluation of alternatives.

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which impacts the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental evaluation of alternatives. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. Examples of non-air quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to indicate the cost to purchase and operate the control technology. The capital and operating/annual cost is estimated based on the established design parameters. Information for the design parameters should be obtained from established sources that can be referenced. However, documented assumptions can be made in the absence of references for the design parameters. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. The cost-effectiveness compares the potential technologies on an economical basis.

Two types of cost-effectiveness are considered in a BACT analysis: average and incremental. Average cost-effectiveness is defined as the total annualized cost of control divided by the annual quantity of pollutant removed for each control technology. The incremental cost-effectiveness is a comparison of the cost and performance level of a control technology to the next most stringent option. It has a unit of (dollars/incremental ton removed). The incremental cost-effectiveness is a good measure of viability when comparing technologies that have similar removal efficiencies.

Step 5—Select BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as BACT for the pollutant and emission unit under review.

1.2 Units 1 and 2 Coal Fired Boiler CO BACT Analysis

This section presents the top-down, five-step BACT process used to evaluate and determine the Project's CO emissions limits for Units 1 and 2. As this analysis will demonstrate, the proposed CO BACT limits for Units 1 and 2 are 0.18 lb/mmBtu and 0.15 lb/mmBtu, respectively.

1.3 Step 1--Identify All Control Technologies

The first step in a top-down analysis, according to the USEPA's October 1990, Draft New Source Review Workshop Manual, is to identify all available control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emission units and the CO emission limits that are being evaluated. CO is formed during the combustion process as a result of the incomplete oxidation of the carbon contained in the fuel; or simply, it is the product of incomplete combustion. The following subsections review the CO control technologies.

1.3.1 Good Combustion Controls

As products of incomplete combustion, CO emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boilers (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. These parameters, however, increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits.

1.3.2 Oxidation Catalysts

This control process utilizes a platinum/vanadium catalyst that oxidizes CO to CO_2. The process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic CO emissions reduction methods have been proven for use on natural gas and oil fueled combustion turbine sources, but not coal fired boilers. The primary technical challenge for including an oxidation catalyst on a coal fired boiler is the location of the catalyst in a high temperature regime, which would most likely be prior to the economizer. This location, along with the potential fouling effects of the flue gas, would render the catalyst ineffective on even a short-term basis.

1.4 Step 2--Eliminate Technically Infeasible Options

Step 2 of the BACT analysis involves the evaluation of all the identified available control technologies in Step 1 of the BACT analysis to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology.

The application of an oxidation catalyst to a coal fired boiler presents many substantial challenges that render this control technology not technically feasible for further consideration as a control alternative for CO. A review of the USEPA RACT/BACT/LAER Clearinghouse (RBLC) reveals that the database contains no record of add-on control equipment for the control of CO, and OUC is not aware of this control technology having ever been applied to a solid fuel boiler. Technical challenges that render an oxidation catalyst control technically infeasible for Units 1 and 2 include the following:

- The oxidation catalyst will not only oxidize CO, but will also oxidize a predominant portion of SO_2 to SO_3. SO_3 in the presence of water (H_2O) forms corrosive and undesirable sulfuric acid vapor emissions. Additionally, the combination of SO_3 with SCR-related ammonia injection (Unit 2) will oxidize even more SO_2 to SO_3 and will likely result in the quick fouling of the air heater and equipment corrosion downstream, and when the flue containing sulfuric acid vapor is cooled, it condenses to form a submicron aerosol mist as it is emitted to the atmosphere. Although not planned at this time, should OUC decide to add additional NO_x controls to Unit 1 such as SCR, the same increased fouling issue would arise.
- Acid gases and trace metals in the flue gas from the combustion of solid fuel will quickly poison the catalyst, making the control technology ineffective in its intended role.

Good combustion controls are considered technically feasible for the control of CO and are considered further in the BACT analysis. CO catalyst is eliminated from further consideration. Table 1-1 summarizes the evaluation of the technically feasible CO options.

Table 1-1 Summary of Step 2 – Eliminate Technically Infeasible Options		
Technology Alternative	Technically Feasible (Yes/No)	
	Available	Applicable
Good Combustion Controls	Yes	Yes
Oxidation Catalyst	Yes	No – There are no documented installations on coal fired boilers that demonstrate it as a viable option.

1.5 Step 3--Rank Remaining Control Technologies by Effectiveness

A search of the information contained in the USEPA BACT/LAER Clearinghouse was conducted to determine the top level of CO control for pulverized coal boilers. A search was also conducted for recently permitted coal fired facilities whose BACT determinations have not yet been included in the current database. The results of this search for coal fired boilers are listed in the Appendix. The data presented in the Appendix show a range of BACT emission limits from 0.10 to 0.25 lb /mmBtu, which indicate the high variability of this pollutant, given the fuel input and boiler design (including fuel type, efficiency, and residence time). The data also provide that the only proposed control for CO in every case is good combustion control.

As previously discussed, CO emissions, as a product of incomplete combustion, are by their nature a function of the specific boiler type and the fuel characteristics, and are thus reflected in the emissions guarantees that vendors are willing to make. Additionally, the values given in the Appendix represent BACT limits for new boilers where as Units 1 and 2 are existing units being retrofitted with Low NO_x Burners/Overfire Air (LNB/OFA) systems for the sole purpose of reducing NO_x emissions as a strategy for compliance with CAIR and as such cannot be optimized as effectively as a new unit given the fixed design considerations of an existing unit. This is illustrated further in the proposed emission rate for Unit 2 of 0.15 lb/mmBtu versus the proposed emission rate for Unit 1, which is almost 10 years older than Unit 2, of 0.18 lb/mmBtu. Both emissions rates are based on vendor guarantees for each specific unit).

Therefore, it is more appropriate to focus on existing units that have recently undergone similar retrofit installations and permit actions. The Department recently issued a draft permit for Lakeland Electric's C.D. McIntosh, Jr. Power Plant for the installation of LNB/OFA on Unit 3. The BACT limit proposed for that unit, based on vendor guarantee, was 0.20 lb/mmBtu. Similarly, the Department recently established a CO emission rate for Units 1 and 2 of 0.20 lb/mmBtu for the Seminole Generating Station. The guarantees proposed for OUC's Stanton Energy Center Units 1 and 2 are each lower than the recently permitted installations discussed immediately above.

1.6 Step 4--Evaluate Most Effective Controls and Document Results

In the following subsections, the technically feasible control alternatives are evaluated in a comparative approach with respect to their energy, environmental, and economic impacts on the Project.

1.6.1 Energy Evaluation of Alternatives

There are no significant energy impacts that would preclude the use of good combustion controls to limit the emissions of CO.

1.6.2 Environmental Evaluation of Alternatives

As previously discussed, the typical good combustion control measures taken to minimize the formation of CO, namely higher combustion temperatures, additional excess air, and optimum air/fuel mixing during combustion, are often counterproductive to the control of NO_x emissions during combustion. A proper balance of this phenomenon is a necessary task in obtaining and complying with the manufacturer's guarantees, since overly aggressive CO limits can jeopardize NO_x emissions design considerations.

1.6.3 Economic Evaluation of Alternatives

Since there is only one feasible control technology to limit the emissions of CO from Units 1 and 2, a comparative cost analysis is not applicable.

1.7 Step 5--Select CO BACT

OUC has determined that good combustion controls represent CO BACT for the Units 1 and 2. Consistent with the top control (i.e., good combustion practices) identified in Section 1.3, OUC proposes a CO BACT emissions limit of 0.18 lb/mmBtu for Unit 1 and 0.15 lb/mmBtu for Unit 2. The proposed BACT levels are based on LNB/OFA vendor guarantees for each of the units subsequent to the installation of the NO_x control technologies. Table 1-2 summarizes the CO BACT determinations for Units 1 and 2.

Table 1-2 Units 1 and 2 CO BACT Determinations		
	Emission Limit (lb/mmBtu)	
Control Technology	Unit 1	Unit 2
Good Combustion Controls	0.18	0.15

Note:
Emission limits are requested on a 30-day basis.

Appendix
To Attachment 1

CO Top Down RBLC Clearinghouse Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (LB/MBTU)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
HARDIN GENERATOR PROJECT	ROCKY MOUNTAIN POWER, INC.	MT	Subbituminous	116	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
LAMAR LIGHT & POWER POWER PLANT	LAMAR UTILITIES BOARD DBA LAMAR LIGHT & POWER	CO	Subbituminous/Bituminous Blend	44	CFB	0.150	3-Hr (75.3 lb/h)	GCC	Permit issued	BACT-PSD	RBLC
OTTER TAIL POWER COMPANY	OTTER TAIL POWER COMPANY	SD	Subbituminous	600	PC	0.150	3-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
GLADES POWER PARK	FLORIDA POWER & LIGHT COMPANY	FL	Bituminous/Pet Coke	2X980	PC	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
WHITEPINE ENERGY STATION	LS POWER DEVELOPMENT	NV	PRB	3x530	PC	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
SWEPCO UNIT	AMERICAN ELECTRIC POWER (AEP)	AR	PRB	600	PC	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
BULL MOUNTAIN, NO. 1, LLC - ROUNDUP POWER PROJECT	BULL MOUNTAIN DEV. COMPANY	MT	Subbituminous	2X390	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
ESTILL COUNTY ENERGY PARTNERS	ESTILL COUNTY ENERGY PARTNERS	KY	Bituminous	110	CFB	0.150	30-Day	GCC	Proposed	BACT-PSD	Reg Spreadsheet
EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA (UNIT 3)	EAST KENTUCKY POWER COOP., INC.	KY	Bituminous	270	CFB	0.150	30-Day	GCC	Permit issued	BACT-PSD	RBLC
CLIFFSIDE	DUKE POWER	NC	Subbituminous/Bituminous Blend	2x800	PC	0.150	3-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
PALATKA GENERATIING STATION	SEMINOLE ELECTRIC COORP	FL	Bituminous	800	PC	0.150	3-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
WPS - WESTON PLANT (UNIT 4)	WISCONSIN PUBLIC SERVICE	WI	PRB	500	PC	0.150	24-Hr	GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
WHELAN ENERGY CENTER	HASTINGS UTILITIES	NE	Subbituminous	220	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
MUSTANG GENERATING STATION	MUSTANG ENERGY (PEABODY)	NM	Subbituminous	300	PC	0.150		GCC	Under review - BACT unresolved	BACT-PSD	Reg Spreadsheet
PRAIRIE STATE GENERATING STATION	PEABODY	IL	Bituminous	2X750	PC	0.150		GCC	Permit issued - under appeal	BACT-PSD	Reg Spreadsheet
CALAVERAS LAKE STATION (J K SPRUCE)	CITY PUBLIC SERVICE OF SAN ANTONIO	TX	Subbituminous	750	PC	0.150		GCC	Permit issued	BACT-PSD	Reg Spreadsheet
HUGO STATION	WESTERN FARMERS ELECTRIC COOP	OK	Subbituminous	750	PC	0.150		GCC	Permit issued	BACT-PSD	Reg Spreadsheet
MANITOWOC PUBLIC UTILITIES	MANITOWOC PUBLIC UTILITIES	WI	Coal/Pet Coke	64	CFB	0.150		GCC	Permit issued	BACT-PSD	RBLC
LONGLEAF ENERGY ASSOCIATES	LS POWER DEVELOPMENT	GA	Subbituminous/Bituminous Blend	2x600	PC	0.150	30-Day	GCC	Permit issued	BACT-PSD	Reg Spreadsheet
TWIN OAKS POWER PLANT (UNIT 3)	SEMPRA GENERATION	TX	Lignite	600	PC	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
SANDY CREEK ENERGY STATION	SANDY CREEK ENERGY ASSOCIATES	TX	Subbituminous	800	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
MUTIPLE GENERATING STATIONS	TXU	TX		800	PC	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
FORMOSA	FORMOSA PLASTICS CORP	TX	Subbituminous/Pet Coke	2X150	CFB	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet

CO Top Down RBLC Clearinghouse Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (LB/MBTU)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
EAST KENTUCKY POWER COOP., INC./SPURLOCK POWER STA (Unit 4)	EAST KENTUCKY POWER COOP., INC.	KY	Bituminous	300	CFB	0.100	30-Day	GCC	Draft Permit	BACT-PSD	Reg Spreadsheet
HIGHWOOD GENERATING STATION	SOUTHERN MONTANA ELECTRIC GENERATION & TRANSMISSION COOP	MT	Subbituminous	270	CFB	0.100	1-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
INDECK ELWOOD	INDECK ELWOOD	IL	Bituminous	2X330	CFB	0.100		GCC	under appeal - EAB remand	BACT-PSD	Reg Spreadsheet
TRIMBLE COUNTY GENERATINIG STATION	LOUISVILLE GAS & ELECTRIC COMPANY	KY	Subbituminous/Bituminous Blend	750	PC	0.100	3-Hr	GCC	Permit Issued	BACT-PSD	Reg Spreadsheet
THOROUGHBRED GENERATING STATION	THOROUGHBRED GENERATING COMPANY, LLC (PEABODY)	KY	Bituminous	2X750	PC	0.100	30-Day	GCC	Permit issued	BACT-PSD	RBLC
DESERT ROCK ENERGY FACILITY	SITHE GLOBAL	NM	Subbituminous	2X750	PC	0.100	24-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
TOUQUOP ENERGY PROJECT	TOUQUOP ENERGY PROJECT	NV	Subbituminous	750	PC	0.100	24-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
ELY ENERGY CENTER	SIERRA PACIFIC & NV POWER	NV	Subbituminous	2X750	PC	0.100	24-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
MAIDSVILLE	LONGVIEW POWER, LLC	WV	Bituminous	600	PC	0.110	3-Hr	GCC	Permit issued	BACT-PSD	RBLC
SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	UT	Subbituminous	270	CFB	0.1150	1-Hr	GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
ELM ROAD GENERATING STATION (EXISTING OAK CREEK FACILITY	WISCONSIN ENERGY	WI	Subbituminous	2X615	PC	0.120		GCC	Permit Issued	BACT-PSD	Reg Spreadsheet
COMANCHE STATION (UNIT 3)	XCEL ENERGY	CO	Subbituminous	750	PC	0.130	8-Hr	GCC	Permit issued	BACT-PSD	Reg Spreadsheet
BIG CAJUN II POWER PLANT	LOUISIANA GENERATING, LLC	LA	Subbituminous	675	PC	0.135	12-Month	GCC	Permit issued	BACT-PSD	RBLC
IATAN GENERATING STATION (UNIT 2)	KANSAS CITY POWER & LIGHT	MO	Subbituminous	800	PC	0.140	30-Day	GCC	Permit issued	BACT-PSD	RBLC
COTTONWOOD ENERGY CENTER	BHP BILLITON	NM	Subbituminous	500	PC	0.140		GCC	Proposed	BACT-PSD	Reg Spreadsheet
SOUTH HEART POWER PROJECT	GREAT NORTHERN POWER DEVELOPMENT	ND	Lignite	500	CFB	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet
WYGEN 3	BLACK HILLS CORPORATION	WY	Subbituminous	100	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC
TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	PRB	200	PC	0.150	24-Hr	GCC	Permit issued	BACT-PSD	RBLC
HOLCOMB POWER PLANT	SUNFLOWER ELECTRIC POWER	KS	PRB	3x700	PC	0.150		GCC	Draft Permit	BACT-PSD	Reg Spreadsheet
INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	UT	Subbituminous/Bituminous Blend	900	PC	0.150	30-Day	GCC	Permit issued	BACT-PSD	RBLC
WYGEN 2	BLACK HILLS CORPORATION	WY	Subbituminous	500	PC	0.150		GCC	Permit issued	BACT-PSD	RBLC
BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	PA	Waste Coal	272	CFB	0.150		GCC	Permit issued - under appeal	BACT-PSD	RBLC/Reg Spreadsheet
BONANZA	DESERET GENERATION & TRANSMISSION	UT	Waste Coal	110	CFB	0.150		GCC	Proposed	BACT-PSD	Reg Spreadsheet

CO Top Down RBLC Clearinghouse Review Results

FACILITY	COMPANY	STATE	FUEL	SIZE (MW)	BOILER TECHNOLOGY	LIMIT (LB/MBTU)	AVERAGING PERIOD	CONTROL TECHNOLOGY	STATUS	NSR BASIS	DATA SOURCE
ELK RUN ENERGY STATION	LS POWER DEVELOPMENT	IA	Subbituminous/Bituminous Blend	750	PC	0.150	30-Day	GCC	Proposed	BACT-PSD	Draft Application
GASCOYNE GENERATING STATION	MONTANA DAKOTA UTILITIES / WESTMORELAND POWER	ND	Lignite	175	CFB	0.154	3-Hr	GCC	Permit issued	BACT-PSD	RBLC
AMERICAN MUNICIPAL POWER OHIO GENERATING STATION	AMP-OHIO	OH	Subbituminous/Bituminous Blend	2x480	PC	0.154	3-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
MIDAMERICAN ENERGY COMPANY	MIDAMERICAN ENERGY COMPANY	IA	PRB	790	PC	0.154	24-Hr	GCC	Permit issued	BACT-PSD	RBLC
SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	SC	Bituminous	2X660	PC	0.160		GCC	Permit issued	BACT-PSD	RBLC
OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	NE	Subbituminous	660	PC	0.160	3-Hr	GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
PEE DEE GENERATING STATION	SANTEE COOPER	SC	Bituminous/Pet Coke	2X660	PC	0.160	3-Hr	GCC	Proposed	BACT-PSD	Reg Spreadsheet
CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	MO	Subbituminous	275	PC	0.160		GCC	Permit issued	BACT-PSD	RBLC
PLUM POINT ENERGY	PLUM POINT ASSOCIATES, LLC	AR	Subbituminous	800	PC	0.160		GCC	Permit issued	BACT-PSD	RBLC
OAK GROVE (UNITS 1 & 2)	TXU	TX	Lignite	2x800	PC	0.170		GCC	Proposed	BACT-PSD	Reg Spreadsheet
GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	PA	Waste Coal	2X250	CFB	0.200		GCC	Permit issued - under appeal	BACT-PSD	RBLC
WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	WV	Waste Coal	98	CFB	0.200	24-Hr	GCC	Permit issued - under appeal	BACT-PSD	RBLC
RIVER HILL POWER COMPANY, LLC	RIVER HILL POWER COMPANY, LLC	PA	Waste Coal	290	CFB	0.250	12-Month	GCC	Permit issued	BACT-PSD	RBLC/Reg Spreadsheet
HUNTER	PACIFICORP	UT	Subbituminous	575	PC				Proposed	BACT-PSD	Reg Spreadsheet - CO Limit Not Listed

Color Code Legend

Data from EPA Regions 4 and 7 Spreadsheet

Data from Draft Application

Data from EPA's RBLC Clearinghouse

Attachment 2

Air Quality Impact Analysis
and
Additional Impact Analysis

1.0 Air Quality Impact Analysis

The following sections discuss the air dispersion modeling performed for the Prevention of Significant (PSD) air quality impact analysis (AQIA) for that PSD pollutant which has a significant emission increase due to the modification greater than the PSD significant emission rate (i.e. CO). The specific modification requiring this PSD application is the installation of Low NO_x Burners/Overfire Air (LNB/OFA) systems at Units 1 and 2 of the Stanton Energy Center. This AQIA was conducted in accordance with United States Environmental Protection Agency's (USEPA) *Guideline on Air Quality Models* (incorporated as Appendix W of 40 CFR 51).

1.1 Model Selection

Consistent with the Appendix W *Guideline on Air Quality Models*, the American Meteorological Society/Environmental Protection Agency (AMS/EPA) Regulatory Model (AERMOD) (Version 07026) air dispersion model was used to predict maximum ground-level concentrations associated with the modification. AERMOD is the product of AMS/EPA Regulatory Model Improvement Committee (AERMIC), formed to introduce state-of-the-art modeling concepts into USEPA's air quality models. AERMOD incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain. The AERMOD model includes a wide range of options for modeling air quality impacts of pollution sources.

1.2 Model Input and Options

This section discusses the model input parameters, source and emission parameters, and the AERMOD model options and input databases.

1.2.1 Model Input Source Parameters

The AERMOD model was used to determine the maximum predicted ground-level concentration for CO and its applicable averaging periods resulting from the modification. The stack parameters and emissions rates used in the model for Units 1 and 2 are presented in Table 1-1. Stack parameters were based on information contained in the appropriate FDEP forms submitted to the Department in February 2007. CO emissions were based on vendor guarantees after LNB/OFA installation on a lb/mmBtu basis and each unit's Title V-listed heat input of 4,286 mmBtu/hr. This was a conservative approach in that it accounts for total CO emissions post LNB/OFA modification in the model and not simply the increase in CO emissions due to the modification.

Table 1-1
Stack Parameters and Emission Rates
Used in the AERMOD Model

Source	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	CO Emission Rate (g/s)
Unit 1	167.64	5.79	25.44	325.93	97.21
Unit 2	167.64	5.79	23.47	324.26	81.00

Note:
Emission rates based on vendor guarantees for CO after the installation of LNB/OFA systems. Specifically, 0.18 lb/mmBtu for Unit 1 and 0.15 lb/mmBtu for Unit 2. Each unit's Title V-listed heat input of 4,286 mmBtu/hr was used in the calculations to derive lb/hr emission rates which were converted to the modeling units of g/s.

1.2.2 Good Engineering Practice and Building Downwash Evaluation

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. In accordance with regulations, the stacks do not exceed their GEP heights and structure-induced downwash was therefore accounted for within the model.

For these analyses, the buildings and structures of the facility were analyzed to determine the potential to influence the plume dispersion from Units 1 and 2. Building and structure dimensions and relative locations were entered into the USEPA's Plume Rise Model Enhancement (PRIME) version of the Building Profile Input Program (BPIP) to produce an AERMOD input file with direction-specific building downwash parameters.

1.2.3 Model Default Options

Since the AERMOD model is especially designed to support the USEPA's regulatory modeling program, the regulatory modeling options are considered the default mode of operation for the model. These options include the use of stack-tip downwash and a routine for processing averages when calm winds or missing meteorological data occur.

1.2.4 Receptor Grid and Terrain Considerations

The air dispersion modeling receptor locations were established at appropriate distances to ensure sufficient density and aerial extent to adequately characterize the pattern of pollutant impacts in the area. Specifically, a nested rectangular grid network that extends out 15 km from the center of the facility was used. The nested rectangular grid network consists of three tiers: the first tier extends from the center of the site to 3 km with 100 m spacing; the second tier extends from 3 km to 6 km with 250 m spacing; and the third tier extends from 6 km to 15 km with 500 m spacing. Receptor spacing at a 50 m interval was used along the fence line. Figure 1-1 illustrates the nested rectangular grid used in the model.

Terrain elevations at receptors were obtained from 7.5-minute United States Geological Survey (USGS) Digital Elevation Model (DEM) files and incorporated into the AERMOD model. There is no distinction in AERMOD between elevated terrain below release height and terrain above release height, as with earlier regulatory models that distinguished between simple terrain and complex terrain. For applications involving elevated terrain, the user must now also input a hill height scale along with the receptor elevation. To facilitate the generation of hill height scales for AERMOD, a terrain preprocessor, called AERMAP, has been developed by USEPA. For each receptor, AERMAP searches for the terrain height and location that has the greatest influence on dispersion. The same receptor grid and terrain elevations that were used and approved in the modeling submitted for the Stanton B IGCC project in February 2006 was used in this analysis for modeling consistency purposes and to aide in the review of the modeling.

1.2.5 Meteorological and Land Use Data

The AERMOD model utilizes a file of surface boundary layer parameters and a file of profile variables including wind speed, wind direction, and turbulence parameters. These two types of meteorological inputs are generated by the meteorological preprocessor for AERMOD, which is called AERMET. AERMET includes three stages of preprocessing of the meteorological data. The first two stages extract, quality check, and merge the available meteorological data. The third stage requires input of certain surface characteristics (surface roughness, Bowen ratio, and Albedo) from the proposed location. AERMET requires hourly input of specific surface and upper air meteorological data. These data at a minimum include the wind flow vector, wind speed, ambient temperature, cloud cover, and morning radiosonde observation, including height, pressure, and temperature. Surface characteristics in the vicinity of the emissions sources are important in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface affect the calculations of the boundary layer parameters and are quantified by the following variables: surface roughness length, surface Albedo, and Bowen ratio, respectively.

The same meteorological data files that were used and approved in the modeling submitted for the Stanton B IGCC project in February 2006 were used in this analysis for modeling consistency purposes and to aide in the review of the modeling. Specifically, the meteorological data is from Orlando International Airport (WBAN 92801) for surface data and Tampa Bay/Ruskin (WBAN 12842) for upper air data for 1996 through 2000. The final surface and profile files for each meteorological year are contained on the CD with this response submittal.

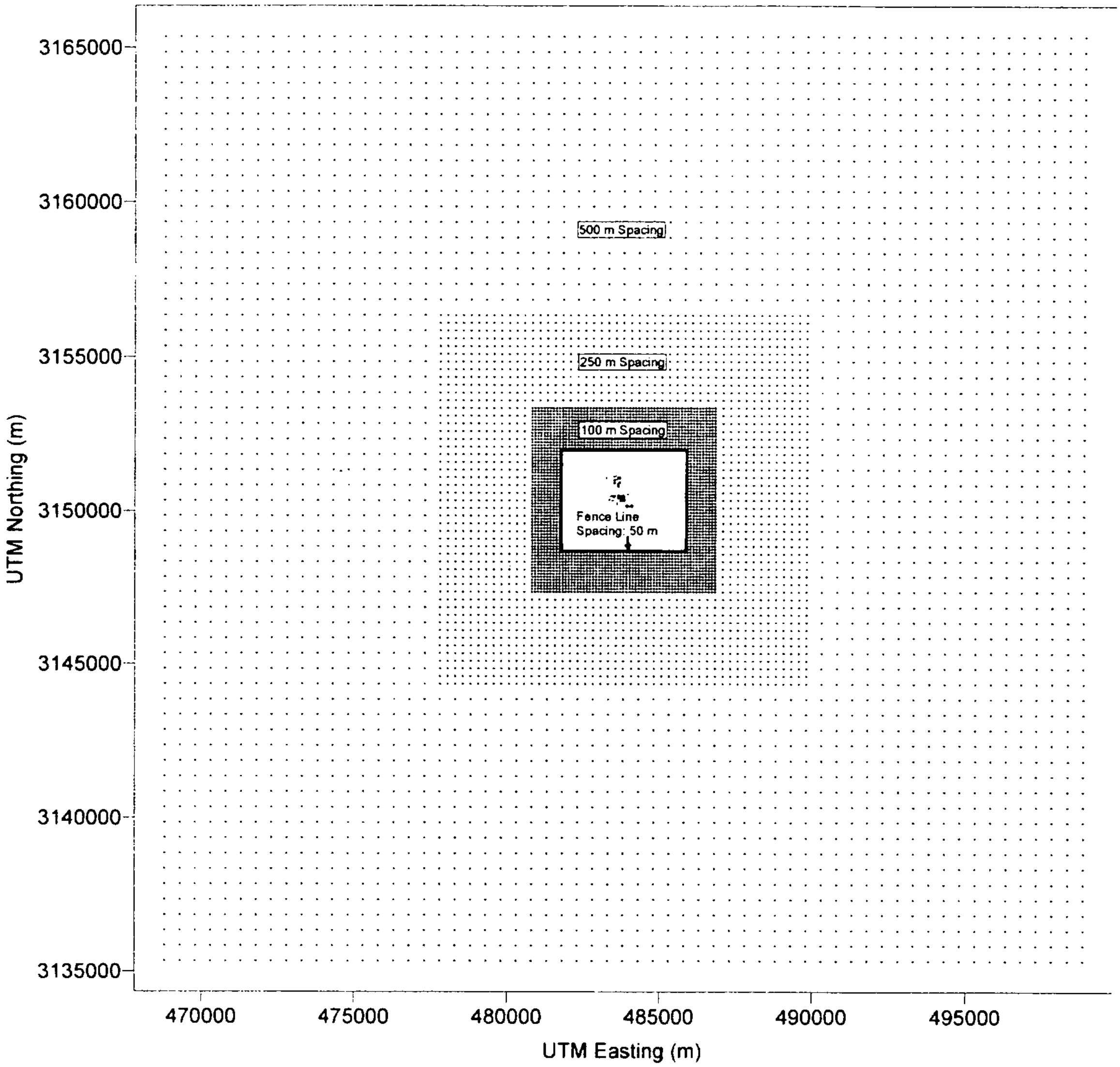

Figure 1-1
Receptor Location Plot

1.3 Model Results

As presented in the response letter, the increase in emissions from Units 1 and 2 due to the modification of adding the LNB/OFA system for NO_x control exceeds the PSD significant emission thresholds for CO. In accordance with the *Guideline*, AERMOD air dispersion modeling was performed as described in the preceding sections. Table 1-2 compares the maximum model predicted concentrations for each applicable averaging period with the PSD Class II significant impact levels (SILs) and the De Minimis monitoring requirements. As Table 1-2 indicates, the maximum model-predicted concentrations are less than the PSD Class II SILs for each applicable averaging period. Therefore, under the PSD program, no further air quality impact analyses (i.e., PSD increment and NAAQS analyses) are required.

If any of the maximum impacts, from each year and averaging period modeled, occurred at the edge of or beyond the 100 m fine grid, a 100 m refined receptor grid would be placed around the impact to ensure that an absolute maximum concentration was obtained from the model. This procedure was not required, as each of the maximum impacts were within the 100 m fine grid.

Additionally, as indicated in Table 1-2, the maximum predicted concentrations are less than the pre-construction monitoring De Minimis levels for the applicable averaging period. Therefore, by this application, the applicant requests an exemption from the PSD pre-construction monitoring requirements. The electronic modeling files are on the CD provided with this response submittal.

Table 1-2
AERMOD Model-Predicted Class II Impacts

Pollutant	Averaging Period	Model-Predicted Impact[a] (μg/m^3)	PSD Class II SIL[b] (μg/m^3)	Exceed SIL?	De Minimis Monitoring Level[c] (μg/m^3)	Pre-Construction Monitoring Required?
CO	8 Hour	38.65	500	NO	575	NO
	1 Hour	103.19	2,000	NO	--	N/A

[a]Impacts represent the highest first high model-predicted concentration from all 5 years of meteorological data modeled.
[b]Predicted impacts that are below the specified level indicate that the project will not have predicted significant impacts for that pollutant and further modeling is not necessary for that pollutant.
[c]This criterion is used to determine if pre-construction ambient air monitoring is required to assess current and future compliance with National Ambient Air Quality Standards.
The full range of model-predicted impacts is given in electronic output on the CD included with this response submittal.

2.0 Additional Impact Analyses

The following sections discuss the modifications' impacts upon commercial, residential, and industrial growth, as well as vegetation and soils, and visibility.

2.1 Commercial, Residential, and Industrial Growth

Because the modifications are of a pollution control nature and being installed at an existing facility, it is anticipated that little growth will be associated with its operation. There will be an increase in the local labor force during the construction phase of the modifications, but this increase will be temporary, short-lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the facility. The central Florida area has sufficient temporary accommodations to house any temporary labor that may come from outside the commuting area.

No additional electrical generating capacity will be created by modifications such that there would be a significant effect upon the industrial growth in the immediate area.

Population increase is a secondary growth indicator of potential increases in air quality levels. Changes in air quality due to population increase are related to the amount of vehicle traffic, commercial/institutional facilities, and home fuel use. According to the US Census Bureau, the population of Orange County has grown by approximately 50 percent between the 1980 and 2000 censuses and an additional 16.4 percent through the first half of 2006. It can be concluded that the air quality impacts associated with secondary growth will not be significant because the increase in population due to the operation of the units post-modification will be little to none, especially when compared to the overall existing population size of the surrounding area (896,344 people within Orange County as of the 2000 census, 1,043,500 by the 2006 estimate).

2.2 Vegetation, Soils, and Wildlife

The NAAQS were established to protect public health and welfare from any adverse effects of air pollutants. The definition of public welfare also encompasses vegetation, soils, and wildlife. Specifically, and as indicated in the *Draft New Source Review Workshop Manual* (EPA, 1990), ambient concentrations below the secondary NAAQS will not result in harmful effects for most types of soils and vegetation.

The criteria pollutant which triggered an additional impact analysis is CO. Comparing the modeled impacts presented in Table 1-2 to the NAAQS as the basis for assessing impacts indicates CO model-predicted impacts are well below the standards (i.e., orders of magnitude below). The impacts are even less than the much lower SIL thresholds as discussed previously.

Additional literature suggests that CO does not poison vegetation since it is rapidly oxidized to form CO_2 which is used for photosynthesis. However, extremely high concentrations can reduce the photosynthetic rate. According to the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plant, Soils, and Animals*, hereafter referred to as EPA Screening Document, for the most sensitive vegetation, a CO concentration of 1,800,000 micrograms per cubic meter (1 week averaging period) could potentially reduce the photosynthetic rate. The maximum model-predicted 1-hour CO impact of 103.19 $\mu g/m^3$ produced by Units 1 and 2 is significantly (more than three orders of magnitude) lower than this screening level (even at a conservative 1 hour averaging period using the maximum expected emissions). Because the emissions do not significantly impact the NAAQS or the Screening levels discussed above, it is reasonable to conclude that no adverse effects on soils and vegetation will occur.

Furthermore, since the installation of the LNB/OFA systems will decrease the emissions of NO_x, the modifications are expected to improve the units' current impact on soils, vegetation, and wildlife. There would also be an expected improvement in ozone concentrations as NO_x is a precursor pollutant to ozone formation.

2.3 Visibility

As previously discussed in this submittal, the modifications will result in significant decreases in NO_x and SO_2 emissions from Units 1 and 2 while experiencing increases in CO emissions due to the NO_x optimizations. The decreases in NO_x and SO_2 will improve visibility related indices from Units 1 and 2. Additionally, CO emissions are not a visibility impairing pollutant. As such, and commensurate with similar projects recently approved by the Department, OUC has not performed a Class II visibility or Class I regional haze analysis as part of this application.

Attachment 3

Update to FDEP Forms

APPLICATION INFORMATION

Professional Engineer Certification

<table>
<tr><td>1. Professional Engineer Name:
Registration Number: 64188</td></tr>
<tr><td>2. Professional Engineer Mailing Address...
Organization/Firm: Black & Veatch
Street Address: 9000 Regency Parkway, Suite 300
City: Cary State: NC Zip Code: 27518</td></tr>
<tr><td>3. Professional Engineer Telephone Numbers...
Telephone: (919) 462-7415 ext. Fax: (919) 468-9212</td></tr>
<tr><td>4. Professional Engineer Email Address: newlandlt@bv.com</td></tr>
<tr><td>5. Professional Engineer Statement:
I, the undersigned, hereby certify, except as particularly noted herein*, that:
(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and
(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.
(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☑, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.
(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.
(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here , if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

[signature] 8.24.07
Signature Date

(seal)</td></tr>
</table>

* Attach any exception to certification statement.

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☑ Attached, Document ID: Attach. A (Feb 07 App.) ☐ Previously Submitted, Date: ___
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☑ Attached, Document ID: Attach. B (Feb 07 App.) ☐ Previously Submitted, Date: ___
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☑ Attached, Document ID: Attach. C (Feb 07 App.) ☐ Previously Submitted, Date: ___

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☐ Attached, Document ID:________ ☑ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☑ Attached, Document ID: Attach. D (Feb 07 App.)
3.	Rule Applicability Analysis: ☑ Attached, Document ID: Attach. E (Feb 07 App.)
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☑ Attached, Document ID: Attach. F (Feb 07 App.) ☐ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☑ Attached, Document ID: Attach. G (Feb 07 App.) ☐ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☑ Attached, Document ID: Attachment 2 of this submittal ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☑ Attached, Document ID: Attachment 2 of this submittal ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☑ Attached, Document ID: Attachment 2 of this submittal ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☑ Attached, Document ID: Attachment 2 of this submittal ☐ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_________ ☑ Not Applicable

1.8 F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL, FUGITIVE, AND ACTUAL EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>
Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 771.5 lb/hour 3379.2 tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.18 lb/mmBtu Reference: Vendor guarantee	7. Emissions Method Code: 0
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: (4286 mmBtu/hr) x (0.18 lb/mmBtu) = 771.5 lb/hr (4286 mmBtu/hr) x (0.18 lb/mmBtu) x (8760 hr/yr) x (ton/2000 lb) = 3379.2 tpy	
11. Potential, Fugitive, and Actual Emissions Comment:	

FACILITY INFORMATION

EMISSIONS UNIT INFORMATION
Section [1] of [7] Page

POLLUTANT DETAIL INFORMATION
[2] of [14]

1.9 F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: Guarantee	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.18 lb/mmBtu	4. Equivalent Allowable Emissions: 771.5 lb/hour 3379.2 tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): Allowable emission value is based on vendor guarantee after Low NOx Burner/Overfire Air system installation.	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	