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Golder Associates

September 5, 2000 9939570

Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. A.A. Linero, P.E.

RE: CALPINE CONSTRUCTION FINANCE COMPANY, LP
OSPREY ENERGY CENTER
COMMENTS ON DRAFT AIR CONSTRUCTION PERMIT; RESPONSES TO EPA COMMENTS ON APPLICATION FOR PERMIT TO CONSTRUCT

Dear Mr. Linero:

The following information provides comments to the draft air construction permit for the proposed Osprey Energy Center in Auburndale, Polk County, Florida prepared by the Florida Department of Environmental Protection (DEP). In addition, responses have been prepared that address the comments made by the U.S. Environmental Protection Agency (EPA) dated June 21, 2000 regarding the air construction permit application.

COMMENTS TO THE DRAFT AIR CONSTRUCTION PERMIT
Comments to the draft air construction permit were discussed in a meeting held with DEP on June 29, 2000. A summary of these comments is presented in Attachment 1 to this letter.

EPA COMMENTS AND RESPONSES
Comment 1

1. In November 1999, ABB ALSTOM POWER announced the availability of $SCONO_x$ systems for any size combustion turbines. Region 4 therefore considers this control method technically feasible for Osprey's combined cycle CTs. Accordingly, FDEP should require the Osprey Energy Center to provide a project-specific BACT analysis for $SCONO_x$ (economics, environmental impacts, and energy use) before issuing a final permit.

Response: Although $SCONO_x$™ is theoretically technically feasible, it has not been demonstrated on an "F" Class combustion turbine. Performance data on future applications on "F" Class turbines considering $SCONO_x$™ will only likely be available after 2002, well after the Osprey Energy Center is scheduled for construction. The $SCONO_x$™ system has only been operated on a 32 MW facility in California since 1996 and a 5 MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The $SCONO_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different catalyst chambers for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that oxygen is not introduced and regeneration gas (hydrogen) is introduced. There is concern that damper seal leaks would be significant as applied to the large volume flows associated with an "F" Class CT. While ammonia is not required for the $SCONO_x$™ system, the turbine backpressure with $SCONO_x$™ is greater than SCR (about 60%) and $SCONO_x$™ requires natural gas and steam for regeneration of the catalyst beds. In contrast, SCR is a proven and demonstrated technology that can achieve the same NO_x reduction performance.

While ammonia is not used or emitted from a $SCONO_x$™ system, there are substantial natural gas and energy requirements for the system that would directly produce air pollutants. The natural gas required to produce the steam needed for $SCONO_x$™ is equivalent to 27 mmBtu/hr or 235,200 mmBtu/year. In contrast, the natural gas requirement needed for SCR is equivalent to 1.8 mmBtu/hr or 15,600 mmBtu/year. These energy requirements, combined with the turbine backpressure and electrical usage would increase emissions of carbon dioxide by about 23,800 ton/year. When all the energy requirements for $SCONO_x$™ are considered, it is about 2.3 percent of the combustion turbine heat input. SCR results in an additional 0.3 percent of the combustion turbine heat input.

The estimated capital cost for $SCONO_x$™ developed for one turbine/HRSG unit for the proposed Osprey Energy Center is $30 million. This capital cost estimate is based on information supplied by ABB Alstrom and the procedures in the EPA Cost Control Manual. In contrast, the capital costs for SCR is about $3.0 million, which clearly is about one-tenth the cost of a $SCONO_x$™ system. The annualized cost of $SCONO_x$™ is estimated at $6.2 million, while the annualized cost for SCR is $1.6 million. Tables B-3a and B-4a present the capital and annualized costs of SCR and $SCONO_x$™. The cost effectiveness of $SCONO_x$™ is $9,300 per ton of NO_x removed. In contrast, the cost effectiveness of SCR is $2,400 per ton of NO_x removed. The cost per ton of NO_x removed is nearly 4 times higher for the $SCONO_x$™ system than for SCR and incurs the uncertainty in its lack of demonstrated feasibility on large turbines.

Comment 2

2. We suggest you verify the emission factor used by Golder Associates to estimate potential formaldehyde emissions. The emission factor cited by Golder is only one-fifth of the emission factor cited for formaldehyde from natural gas turbines in the recently revised section 3.1 of AP-42.

Response: Golder Associates has revised the emission factors for hazardous air pollutants (HAPs) to reflect the availability of additional data. The revised HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factor database. A summary of the emission factors and emissions for gas firing is presented in Tables A-2, A-3, A-5, A-6, A-8, and A-9.

Except for formaldehyde, the emission factors are those presented in Tables 3.1-4 and 3.1-5 of the revised AP-42 section for combustion turbines. For formaldehyde, a review of EPA's database was conducted and an emission factor was estimated based on comparisons of the turbines and emission characteristics from EPA's database to those proposed for this project. A discussion regarding this review and estimation of the formaldehyde emission factor is presented here.

The original emission factor for formaldehyde used in the application was from the Electric Power Research Institute (EPRI)- sponsored Electric Utility Trace Substances Synthesis Report. This report was submitted to EPA as part the requirements of the 1990 Clean Air Act Amendments to study potentially toxic air pollutants from utility sources. These data were the most technically accurate and complete data available on emission from utility sources. The emission factor used for the proposed CTs for this Project was 34 $lb/10^{12}$ Btu. It should be recognized that there are still limited data on formaldehyde emissions from large (i.e., > 100 MW) gas turbines.

The recent EPA emission factor suggests formaldehyde emissions from gas turbines of 780 $lb/10^{12}$ Btu when firing natural gas at loads greater than 80 percent. The EPA suggested emission factor for all loads is 3,100 $lb/10^{12}$ Btu. These emission factors for formaldehyde when firing natural gas are not appropriate for the proposed CTs for several reasons. First, and most importantly, the data used to develop the AP-42 emission factors are not representative of the Siemens Westinghouse combustion turbine. Second, an evaluation of the data in the EPA Combustion Turbine Emissions Database clearly suggests a much lower emission factor for formaldehyde. Some of the important aspects of the EPA Gas Turbine Database related to formaldehyde emission are as follows.

- The formaldehyde emissions listed in the database are from small (< 30 MW) gas turbines. The available data are from an average capacity of about 28 MW. More importantly, the median capacity, or the turbine size where an equal number of turbines are above and below that size, is about 15 MW. Data from only 8 large turbines (>30 MW) are included in the EPA database, with a maximum size of 88 MW.
- In contrast to the AP-42 emission factors for formaldehyde, which are based on an average value, the median value in the database is substantially lower. For all loads, the median formaldehyde emission factor is about 320 lb/10^{12} Btu; for turbine loads greater than 50 percent, the median emission factor is about 110 lb/10^{12} Btu. The median emission factor is about 8 to ten times lower than the average factor which demonstrates the wide range in formaldehyde emissions and how individual turbine combustion characteristics can influence the results. The median is a measure of the middle of the distribution and, in distributions where there is symmetry about the mean, the mean and median coincide. However, in highly skewed distributions, as that observed for formaldehyde emissions, the median is more representative of a "truer average" since the median is not influenced by extreme values.
- There is a strong relationship between formaldehyde and CO emissions, as noted by EPA in the support document and, and as observed in the data. Gas turbines with higher CO emissions had higher observed formaldehyde emissions. An evaluation of the coincident CO and formaldehyde data indicates that formaldehyde emissions were 150 lb/10^{12} Btu with CO emissions less than 0.1 lb/mmBtu. The CO emissions from the Siemens Westinghouse 501F turbine are about 0.02 lb/mmBtu under base load conditions and 0.06 lb/mmBtu with power augmentation.

The California Air Resource Borad sponsored a program to develop emission factors for toxic air pollutants. These factors, referred to as California Air Toxic Emission Factors (CATEF), included an emission factor for formaldehyde. The suggested factor is 108 lb/10^{12} Btu.

Based on the available data, formaldehyde emissions would be in the range between 100 and 150 lb/10^{12} Btu. An emission factor of 150 lb/10^{12} Btu is considered appropriate for the Osprey Energy Center as a conservative factor for formaldehyde emissions.

Preliminary test data from a Calpine facility in Pasadena indicate formaldehyde emissions of about 150 lb/10^{12} Btu. Therefore, the emissions factor for formaldehyde developed from the EPA database is similar to the preliminary test data. The AP-42 emission factor for acetaldehyde is 40 lb/10^{12} Btu, which is also similar to the preliminary test data.

EPA developed the emission factors for many of the other HAPs in a manner similar to formaldehyde. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for these HAPs are considered to provide conservative estimates of emissions.

An evaluation of the HAP emissions from the project indicates that emissions are less than 25 tons/year for all HAPs and less than 10 tons/year for any single HAP. As shown in Table2-4, the maximum total emissions of HAPs are estimated to be 8 tons/year with maximum emissions of any single HAPs at 2.6 tons/year (i.e., for formaldehyde). Therefore, the requirements of 40 CFR 63.43 for a maximum achievable control technology are not applicable to the project.

Comment 3

3. The "Public Notice of Intent to Issue PSD Permit" indicates that the combustion turbines for this project will be General Electric PG7241FA units. It is our understanding, as indicated in the preliminary determination and draft PSD permit, that the Osprey Energy Center will be installing Siemens Westinghouse 501FD combustion turbines. If possible, please clarify this inconsistency before the public notice is published.

Response: As a point of clarification, the Siemens Westinghouse 501FD combustion turbines are proposed for the Osprey Energy Center.

We appreciate your timely review of these responses. If you have any additional questions, please contact Mr. Benjamin Borsch of Calpine at (813) 637-3515 or me at (352) 363-5600.

Sincerely,

GOLDER ASSOCIATES INC.

Robert C. McCann Jr. for

Kennard F. Kosky, P.E.
Principal

RCM/jkw

cc: Benjamin Borsch, Calpine, Corporation
R.C.McCann, Golder
R. Douglas Neeley, EPA Region
David S. Dee, Landers & Parsons
M. Halpin
C. Holladay
NPS
B. Oven
SWD

ATTACHMENT 1

Comments On Osprey Draft Permit

Permit Ref.	Sec.	Para.	Line	Comment
Intent to Issue PSD Permit	N/A	2	5	Delete "121 foot" or change to "135 foot"
Public Notice to Issue	N/A	1	4	Change "nitrous" to "nitrogen"
Public Notice to Issue	N/A	2	1	Change "General Electric PG7241FA" to "Siemens Westinghouse 501FD"
Public Notice to Issue	N/A	2	4	Change "...relatively short stacks ..." to "... stacks..."
Public Notice to Issue	N/A	4	Table	NO_x emissions should be reduced from 258 to 227 TPY in order to reflect the reduction of emission concentration from 4.0 to 3.5 ppmvd corrected to 15% O_2. The 227 TPY reflects 3.5 ppmvd (corrected) limit and the emergency gas generator and diesel fire pump.
Technical Evaluation and Preliminary Determination (TEPD)	1.1	1	1	Change "Calpine Construction Finance Company" to "Calpine Construction Finance Company, LP"
TEPD	3	2	1	Change "Calpine Construction & Finance Company, LP" to "Calpine Construction Finance Company, LP"
TEPD	4	3	4&5	Delete "Steam cooling of key components of the 501 F minimizes the need for less efficient air-cooling." F turbines do not employ this technology; G turbines do.
TEPD	6.2	1	NO_x	The NO_x emissions of the 2 CT/DB with duct firing are 218 TPY; the total is 227 TPY. This reflects the 3.5 ppmvd (corrected) limit.
TEPD	6.4.4	2	2	Change "Because no add-on-on control equipment and no reagents are required, there will be no steam plum or tendency to form ammoniated particulate species" to "There will be no steam plume."
Draft Permit	I(pg1)	1	1	Change "Calpine Construction & Finance Co., LP" to "Calpine Construction Finance Company, LP"
Draft Permit	I(pg2)	1	6	Change "230 KV transmission line" to "transmission line"
Draft Permit	III(pg6)	9	2&3	Add "without power augmentation" at end of first sentence since 1,669 MMBtu/hour is based

Permit Ref.	Sec.	Para.	Line	Comment
				on base load conditions. Also, the 1,669 million Btu per hour at ISO conditions is based on Siemens/Westinghouse guarantees but could change depending on the final installation and testing of the 501F units. Calpine understands that, based on the language of the condition, this could be modified based on "as built" performance curves.
Draft Permit	III(pg7)	10	2	The 250 MMBtu/hour is lower heating value (LHV); Change "(HHV)" to "(LHV)".
Draft Permit	III(pg7)	16	1	Change "simple cycle mode" to "without the use of the SCR system except during periods of startup and shut down." It is possible that the unit could operate in simple cycle mode during steam turbine failure or overhaul or during startup. For example, a dump condenser could be installed to manage the steam generated by the HRSG. With such operation, the SCR system would still be operated to meet emission limits but the unit would be in simple cycle mode.
Draft Permit	III(pg7)	19	1	Change "A certification…" to "A manufacturer's certification…"
Draft Permit	III(pg8)	20	2	Change "3-hr block average" to "24-hour block average" to be consistent with DEP's BACT Determination
Draft Permit	III(pg8)	20	6	Add after "27.5 lb/hr" the following "...(at 95°F ambient temperature with power augmentation and duct firing)". The 27.5 lb/hr reflects NO_x emissions when duct firing and power augmentation at 95 °F ambient conditions. This mode is more likely during the summer conditions, under cold weather conditions the emissions are 30.7 lb/hr. This is the maximum mass emission and is based on data from Siemens Westinghouse for that ambient temperature. Data sheets are attached.
Draft Permit	III(pg8)	21	2	Change "10 ppm" to "10 ppmvd"
Draft Permit	III(pg8)	21	5	Change "10 ppm" to "10 ppmvd @ 15% O_2"
Draft Permit	III(pg8)	21	5	Change "45 lb/hr" to "45 lb/hr per unit"
Draft Permit	III(pg8)	21	6	Change "with the duct burner off" to "with the duct burner off and no steam injection for

Permit Ref.	Sec.	Para.	Line	Comment
				power augmentation"
Draft Permit	III(pg8)	21	6	Add "...to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing." Calpine will have a certified CEMS that will demonstrate compliance continuously.
Draft Permit	III(pg8)	22	2 and 3	Change "ppmvd" to "ppmvd @ 15% O_2" and "lb/hr" to "lb/hr per unit"
Draft Permit	III(pg8)	22	5	Add emission limit of 4.2 ppmvd @ 15% O_2 during operations between 60 and 70 percent load per DEPs BACT Determination.
Draft Permit	III(pg8)	23	2	Change "less" to "not greater than"
Draft Permit	III(pg8)	23	5 and 6	Convert the last sentence to a note, since this statement is not relevant to limiting emissions of SO_2.
Draft Permit	III(pg8)	24	2	Change "the combustion turbine" to "each combustion turbine and HRSG train"
Draft Permit	III(pg9)	25	8	This condition would prohibit operation at or below 60 percent load even if the unit can meet the emission limits for CO. Add the following at the end of the condition: "...unless the permittee can demonstrate that the emission limits in Specific Condition III. 21. can be met." The plant will have CEMs and compliance will have to be demonstrated except for the periods outlined in the condition.
Draft Permit	III(pg9)	26	3	Change "3-hr" to "24-hr"
Draft Permit	III(pg9)	27	8	Change "No. 20 through 24" to "No. 20 through 21." Calpine has no way of knowing excess emissions for VOC, SO_2 and PM during startups and shutdowns.
Draft Permit	III(pg9)	29	1-4	Delete "Initial tests shall ... or change of combustors." What constitutes a "substantial modification" is very subjective in this context and any work performed on the units will likely affect only CO and NO_x, which are subject to CEMS. In addition, annual compliance tests were performed during every federal fiscal year. Replace with "Any replacement of the major components of the air pollution control equipment or the combustors (e.g., catalyst change-out or combustor replacement) must demonstrate

Permit Ref.	Sec.	Para.	Line	Comment
				compliance with the CEM based emission limits after the replacement is made. This activity must be identified in the quarterly report. If compliance with the CO emission limit is demonstrated through the CEM after the replacement, then no testing of VOCs is required."
Draft Permit	III(pg9)	29	Bul. 4	Delete the last sentence. The BACT standard should not have any relationship to the "ISO" correction and methods used in EPA Method 20. For annual tests, add that compliance with the BACT standard can be demonstrated during the RATA testing required under 40 CFR Part 75
Draft Permit	III(pg10)	30	8	Change "These excess emission periods…" to "Excess emission periods…"
Draft Permit	III(pg12)	44	All	Calpine understands that the language is taken from the Department's rules and that the appropriate process variables are based on the permit and the test methods prescribed in the permit. Add "No later than 90 days prior to operation, the permittee shall submit for the Department's approval a list of process variables that will be measured to comply with this permit condition."
Draft Permit	III(pg12)	46	Bul. 2	Delete the last sentence of the bullet. The wording presents both interpretation and enforcement difficulties. It is clear that the NO_x emission limit is CEM based and Calpine will operate the SCR system as required by both the emission limit and the manufacturer's requirements to insure the NO_x limit is achieved. See also comments to Bullet 5.
Draft Permit	III(pg12)	46	Bul. 3, ln 8&9	Delete the last two sentences. As discussed in our comments to Bullets 5 and 6 of this paragraph, Calpine proposes continuous monitoring, notification and corrective action planning that renders these two sentences unnecessary.
Draft Permit	III(pg13)	46	Bul. 4	Delete the word "minimum" in reference to the ammonia flow rate in the first sentence. Replace "at a minimum of 100% of the ammonia injection rate determined during the test." with "at an ammonia flow rate

Permit Ref.	Sec.	Para.	Line	Comment
				immediately prior to the NO_x CEM disruption." The system will be operated according to the manufacturer's requirements and information on the flow rate will be provided and the annual tests will include the ammonia emissions. Using an ammonia flow rate just prior to a NO_x CEM failure would reflect the current state of the catalyst while minimizing ammonia emissions. See also comments to Bullet 5.
Draft Permit	III(pg13)	46	Bul. 5	Calpine offers the following as a condition to monitor ammonia emissions. "Ammonia emissions shall be calculated using inlet and outlet NO_x concentrations from the SCR system and ammonia flow supplied to the SCR system. The calculation procedure shall be provided with the CEM monitoring plan required by 40 CFR Part 75." There are several procedures, which can be used to calculate ammonia emissions based on the final CEM design. Examples are attached.
Draft Permit	III(pg13)	46	Bul. 6	Delete. This provision is inappropriate since it assumes that ammonia slip will exceed the 9-ppm limit within a year from the time that the ammonia slip is over 7. Indeed, ammonia testing will occur each year to determine compliance. Moreover, ammonia is not a regulated pollutant under the Clean Air Act except for 112 r provisions. The prior provisions to this paragraph provide the DEP with adequate assurances of continuous compliance. Per our discussion with the Department, replace this condition with: "The permittee shall notify the Department within 2 business days if the calculated ammonia emissions exceed 9 ppmvd corrected to 15% O_2 over a 24-hour block average. The notification shall include a corrective action plan to reduce ammonia emissions to below 9 ppmvd corrected to 15% O_2 over a 24-hour block average."
Draft Permit	III(pg13)	46	Bul. 7	Delete. This provision assumes that the cause of an ammonia slip or NO_x exceedence is saturated catalyst when in fact it could be

Permit Ref.	**Sec.**	**Para.**	**Line**	**Comment**
				another cause (plugged nozzles, pump malfunctions, etc.). The prior provisions provide DEP with adequate assurances of continuous compliance. Calpine has offered language in Bullet 6 that provides notification and corrective actions to limit ammonia emissions.
Draft Permit	III(pg13)	46	Bul. 8	Delete. Calpine is not aware of any data that suggests maintaining a catalyst age of less than 24 months is necessary to ensure compliance with our NO_x or ammonia limits. In addition, each unit will have continuous monitoring of NO_x and ammonia usage (via ammonia flow monitoring), which will provide an indication of the need to replace catalyst. Calpine has offered continuous monitoring and notification procedures (see Bullets 5 and 6) that provide reasonable assurance that the SCR system will comply with ammonia and NO_x emission limits.
Appendix BD	PgBD-3	Tab.1		The Calpine Sutter and Delta Projects were LAER limits, not BACT limits
Appendix BD	PgBD-7	3	4	The $SCONO_x$ unit in Massachusetts is operational; however, it has not provided consistently low NO_x emissions.
Appendix BD	PgBD-8	2	1 and 2	Most of the recent LAER determinations have specified the combination of dry-low NO_x combustors and SCR, not $SCONO_x$.
Appendix BD	PgBD-11	Table	NO_x	Request that EPA Method 7e be added to the compliance procedures for NO_x.

Table 2-1. Stack, Operating, and Emission Data for the Combustion Turbines/HRSG and Duct Burners
Osprey Energy Center Project

		Operating and Emission Data [a] for Ambient Temperarure				
		Combustion Turbine/ HRSG				CT/ HRSG/ Duct Burner
					Power Augmentation	Power Augmentation
Parameter		32 °F	59 °F	95 °F	95 °F	95 °F
Stack Data (ft)						
Height		135	135	135	135	135
Diameter		19	19	19	19	19
100 Percent Load						
Operating Data						
Temperature (°F)		200	200	200	200	200
Velocity (ft/sec)		62.9	60.0	55.2	59.7	60.0
Maximum Hourly Emissions per Unit [b]						
SO_2	lb/hr	11.0	10.4	9.4	10.4	12.0
PM/PM_{10}	lb/hr	22.3	21.1	19.0	19.8	22.8
NO_x	lb/hr	25.8	24.3	22.1	24.4	27.5
CO	lb/hr	45.0	43.0	39.0	106.0	139.3
VOC (as methane)	lb/hr	5.8	5.4	4.9	5.5	12.4
Sulfuric Acid Mist	lb/hr	1.69	1.59	1.44	1.59	1.83
Mercury	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
75 Percent Load						
Operating Data						
Temperature (°F)		200	200	200	-	-
Velocity (ft/sec)		54.8	52.8	50.2	-	-
Maximum Hourly Emissions per Unit [b]						
SO_2	lb/hr	8.6	8.1	7.6	-	-
PM/PM_{10}	lb/hr	19.0	18.2	16.9	-	-
NO_x	lb/hr	20.1	19.0	17.7	-	-
CO	lb/hr	35.0	33.0	31.0	-	-
VOC (as methane)	lb/hr	8.4	7.9	7.4	-	-
Sulfuric Acid Mist	lb/hr	1.31	1.25	1.16	-	-
Mercury	lb/hr	0.00E+00	0.00E+00	0.00E+00	-	-
60 Percent Load						
Operating Data						
Temperature (°F)		200	200	200	-	-
Velocity (ft/sec)		45.9	44.5	42.5	-	-
Maximum Hourly Emissions per Unit [b]						
SO_2	lb/hr	7.4	7.2	6.5	-	-
PM/PM_{10}	lb/hr	16.0	15.4	14.3	-	-
NO_x	lb/hr	17.4	16.8	15.2	-	-
CO	lb/hr	152.0	146.0	133.0	-	-
VOC (as methane)	lb/hr	7.3	7.0	6.3	-	-
Sulfuric Acid Mist	lb/hr	1.14	1.10	1.00	-	-
Mercury	lb/hr	0.00E+00	0.00E+00	0.00E+00	-	-

[a] Refer to Appendix A for detailed information. Data at 100% load and duct firing for 95 °F are based on power augmentation with evaporative cooler on and operating at 95 percent efficiency. With evaporative cooler not operating, emissions are lower. Duct firing is assumed for 100% operating load. No duct firing is assumed for loads less than 100%

[b] Other regulated pollutants are assumed to have negligible emissions. These pollutants include lead, reduced sulfur compounds, hydrogen sulfide, fluorides, beryllium, arsenic, asbestos, vinyl chloride, and radionuclides.

See Appendix A for basis of pollutant emission rates and operating data.

Table 2-4 Summary of Maximum Potential Annual Emissions for the CT/HRSG, Duct Burner, and Cooling Tower

		Annual Emissions (tons/year)[a]					Maximum Emissions (tons/year)[b]				
					Power Augmentation	Duct Burner/ Power Augmentation					
	Load:	100%	75%	60%	100%	100%					
Pollutant	Hours.	8,760	8,760	8,760	8,760	8,760 (@95 Deg. F)	Case A	Case B	Case C	Case D	Overall
One Combustion Turbine- Combined Cycle											
SO_2		45.4	35.6	31.4	45.6	52.4	45.4	47.7	43.0	45.3	47.7
PM/PM_{10}		92.4	79.7	67.6	86.6	99.8	92.4	94.8	87.1	90.6	94.8
NO_x		106	83	73	107	115	106.3	109.1	100.8	103.5	109.1
CO		188	145	639	464	586	188.3	319.0	314.7	396.2	396.2
VOC (as methane)		23.8	34.8	30.6	23.9	53.0	23.8	33.4	25.0	34.6	34.6
Sulfuric Acid Mist		7.0	5.5	4.8	7.0	8.0	7.0	7.3	6.6	6.9	7.3
Mercury		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,3-Butadiene		3.49E-03	2.74E-03	2.41E-03	3.50E-03	4.03E-03	3.49E-03	3.67E-03	3.31E-03	3.48E-03	3.67E-03
Acetaldehyde		3.25E-01	2.55E-01	2.24E-01	3.26E-01	3.75E-01	3.25E-01	3.41E-01	3.08E-01	3.24E-01	3.41E-01
Acrolein		5.19E-02	4.08E-02	3.59E-02	5.21E-02	5.99E-02	5.19E-02	5.46E-02	4.92E-02	5.18E-02	5.46E-02
Benzene		9.74E-02	7.64E-02	6.73E-02	9.78E-02	1.12E-01	9.74E-02	1.02E-01	9.23E-02	9.72E-02	1.02E-01
Ethylbenzene		2.60E-01	2.04E-01	1.79E-01	2.61E-01	3.00E-01	2.60E-01	2.73E-01	2.46E-01	2.59E-01	2.73E-01
Formadehyde		1.22E+00	9.56E-01	8.41E-01	1.22E+00	1.40E+00	1.22E+00	1.28E+00	1.15E+00	1.21E+00	1.28E+00
Naphthalene		1.06E-02	8.28E-03	7.29E-03	1.06E-02	1.22E-02	1.06E-02	1.11E-02	1.00E-02	1.05E-02	1.11E-02
Polycyclic Aromatic Hydrocarbons (PAH)		1.79E-02	1.40E-02	1.23E-02	1.79E-02	2.06E-02	1.79E-02	1.88E-02	1.69E-02	1.78E-02	1.88E-02
Propylene Oxide		2.35E-01	1.85E-01	1.63E-01	2.36E-01	2.72E-01	2.35E-01	2.47E-01	2.23E-01	2.35E-01	2.47E-01
Toluene		1.06E+00	8.28E-01	7.29E-01	1.06E+00	1.22E+00	1.06E+00	1.11E+00	1.00E+00	1.05E+00	1.11E+00
Xylene		5.19E-01	4.08E-01	3.59E-01	5.21E-01	5.99E-01	5.19E-01	5.46E-01	4.92E-01	5.18E-01	5.46E-01
Total HAPs		3.79E+00	2.98E+00	2.62E+00	3.81E+00	4.38E+00	3.79E+00	3.98E+00	3.59E+00	3.78E+00	3.98E+00
Cooling Tower											
PM		4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
PM_{10}		2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Two Combustion Turbines- Combined Cycle											
SO_2		90.8	71.3	62.7	91.1	104.7	90.8	95.4	86.1	90.6	95.4
PM/PM_{10}		185	159	135	173	199.7	185	190	174	181	189.7
NO_x		213	167	147	214	229.6	213	218	202	207	218.2
CO		377	289	1,279	929	1,171.4	377	638	629	792	792.5
VOC (as methane)		47.6	69.6	61.2	47.8	106.0	47.6	66.8	49.9	69.1	69.1
Sulfuric Acid Mist		13.9	10.91	9.60	13.96	16.0	13.91	14.61	13.18	13.87	14.6
Mercury		0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,3-Butadiene		6.98E-03	5.48E-03	4.82E-03	7.01E-03	8.05E-03	6.98E-03	7.33E-03	6.62E-03	6.96E-03	7.33E-03
Acetaldehyde		6.49E-01	5.10E-01	4.49E-01	6.52E-01	7.49E-01	6.49E-01	6.82E-01	6.15E-01	6.48E-01	6.82E-01
Acrolein		1.04E-01	8.15E-02	7.18E-02	1.04E-01	1.20E-01	1.04E-01	1.09E-01	9.85E-02	1.04E-01	1.09E-01
Benzene		1.95E-01	1.53E-01	1.35E-01	1.96E-01	2.25E-01	1.95E-01	2.05E-01	1.85E-01	1.94E-01	2.05E-01
Ethylbenzene		5.19E-01	4.08E-01	3.59E-01	5.21E-01	5.99E-01	5.19E-01	5.46E-01	4.92E-01	5.18E-01	5.46E-01
Formadehyde		2.43E+00	1.91E+00	1.68E+00	2.44E+00	2.81E+00	2.43E+00	2.56E+00	2.31E+00	2.43E+00	2.56E+00
Naphthalene		2.11E-02	1.66E-02	1.46E-02	2.12E-02	2.43E-02	2.11E-02	2.22E-02	2.00E-02	2.11E-02	2.22E-02
Polycyclic Aromatic Hydrocarbons (PAH)		3.57E-02	2.80E-02	2.47E-02	3.58E-02	4.12E-02	3.57E-02	3.75E-02	3.38E-02	3.56E-02	3.75E-02
Propylene Oxide		4.71E-01	3.69E-01	3.25E-01	4.73E-01	5.43E-01	4.71E-01	4.95E-01	4.46E-01	4.70E-01	4.95E-01
Toluene		2.11E+00	1.66E+00	1.46E+00	2.12E+00	2.43E+00	2.11E+00	2.22E+00	2.00E+00	2.11E+00	2.22E+00
Xylene		1.04E+00	8.15E-01	7.18E-01	1.04E+00	1.20E+00	1.04E+00	1.09E+00	9.85E-01	1.04E+00	1.09E+00
Total HAPs		7.59E+00	5.95E+00	5.24E+00	7.61E+00	8.75E+00	7.59E+00	7.97E+00	7.19E+00	7.57E+00	7.97E+00
Two Combustion Turbines- Combined Cycle with Cooling Tower											
PM		193	168	144	182	208	193	198	183	190	198.3
PM_{10}		189	164	139	177	204	189	194	179	185	194.0

[a] Based on 59 °F ambient inlet air temperature except for power augmentation.
Power augmentation and duct firing will be used with CTs operating at 100 percent load, 95 °F ambient inlet air temperature, and evaporative cooler at 95% efficiency. With evaporative cooler not operating, emissions are lower

[b] Maximum emission cases:

Operation	Number of Hours for Operation: Case A	Case B	Case C	Case D
100 % Load	8,760	5,880	5,700	4,380
100 % Load with PA	0	0	1,560	0
100% Load with PA & Duct firing)	0	2880	0	2,880
60% Load	0	0	1,500	1,500
Total hours	8,760	8,760	8,760	8,760

Table 2-5 Summary of Maximum Potential Annual Emissions for the Osprey Energy Center Power Project

Pollutant	Annual Emissions (tons/year) 2 CT/HRSG with Duct Burners	Cooling Tower	Emergency Gas-Fired Generator	Diesel Fire Pump	TOTAL	PSD Significant Emission Rate (tons/year)
SO_2	95	--	0.006	0.056	95	40
PM	190	8.6	0.03	0.34	199	25
PM_{10}	190	4.3	0.03	0.34	194	15
NO_x	218	--	3.8	4.8	227	40
CO	792	--	3.79	1.04	797	100
VOC (as methane)	69.1	--	0.09	0.38	70	40
Sulfuric Acid Mist	14.6	--	Neg.	Neg.	15	7
Mercury	0.0	--	Neg.	Neg.	0.0	0.1

Table A-2. Maximum Emissions for Criteria and Other Regulated Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 100 % Load including Power Augmentation (PA) and Duct Burner (DB)

Parameter	Ambient/Compressor Inlet Temperature						DUCT BURNER (Ambient Temperature)				
	32 °F Case 9	32 °F PA	59 °F Case 6	95 °F Case 3	95 °F Case 2	95 °F Case 1 (PA)	32 °F PA	59 °F Case 6 (DB)	95 °F Case 3 (DB)	95 °F Case 2 (DB)	95 °F Case 1 (DB&PA)
Hours of Operation	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
<u>Particulate from CT and SCR</u>											
Particulate from CT = Emission rate (lb/hr) from CT manufacturer (front- and back-half)											
Basis, lb/hr - provided (a)	16.6	16.6	15.8	14.1	14.4	14.4	16.6	18.0	16.4	16.7	16.6
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (= PM_{10})											
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/lb SO_3											
SO_2 emission rate (lb/hr)- calculated	11.0	11.8	10.4	9.4	9.8	10.4	11.8	11.9	11.0	11.3	12.0
Conversion (%) from SO_2 to SO_3	25	25	25	25	25	25	25	25	25	25	25
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100	100	100	100	100	100	100	100	100
MW $(NH_4)_2$ SO_4/ SO_3 (132/80)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Particulate (lb/hr)- calculated	5.68	6.08	5.35	4.86	5.03	5.36	6.08	6.15	5.66	5.84	6.17
Particulate (lb/hr) from CT + SCR	22.3	22.7	21.1	19.0	19.5	19.8	22.7	24.1	22.0	22.5	22.8
(TPY)	97.6	99.3	92.4	83.2	85.3	86.6	99.3	105.6	96.4	98.6	99.8
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100											
Fuel use (cf/hr)	1,926,087	2,063,063	1,814,130	1,648,913	1,708,696	1,820,652	2,063,063	2,085,870	1,920,652	1,980,435	2,092,391
Sulfur content (grains/ 100 cf) - assumed (b)	2	2	2	2	2	2	2	2	2	2	2
lb SO_2 /lb S (64/32)	2	2	2	2	2	2	2	2	2	2	2
Emission rate (lb/hr)- calculated	11.0	11.8	10.4	9.4	9.8	10.4	11.8	11.9	11.0	11.3	12.0
(lb/hr)- provided (0.2 gr/100 cf) (not used)	1.2	1.2	1.1	1.0	1.1	1.1	1.2	1.1	1.0	1.1	1.1
(TPY)	48.3	51.6	45.4	41.3	42.8	45.6	51.6	52.2	48.1	49.6	52.4
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]											
Basis, ppmvd @15% O_2 (a) (d)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Moisture (%)	7.92	13.11	8.44	10.62	11.08	15.81	13.96	9.40	11.65	12.08	16.73
Oxygen (%)	12.53	11.29	12.51	12.13	11.97	10.90	10.33	11.45	10.97	10.85	9.85
Volume Flow (acfm)	2,509,194	2,661,219	2,417,019	2,264,224	2,317,426	2,438,907	2,673,585	2,429,103	2,276,513	2,329,668	2,451,140
Temperature (°F)	1,088	1,108	1,102	1,133	1,126	1,125	1,108	1,102	1,133	1,126	1,125
Emission rate (lb/hr)- calculated	24.4	26.2	23.0	20.9	21.7	23.1	29.3	26.1	24.0	24.8	26.2
(lb/hr)- provided	25.8	27.6	24.3	22.1	22.9	24.4	30.7	27.4	25.2	26.0	27.5
(TPY)	112.9	120.8	106.3	96.6	100.2	106.8	134.5	114.4	105.2	108.5	114.8
[Ratio lb/hr provided/calculated]	1.056	1.054	1.056	1.056	1.056	1.056	1.049	1.049	1.049	1.049	1.049
Carbon Monoxide (lb/hr) = CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]											
Basis, ppmvd- calculated	12.4	33.5	12.3	12.4	12.6	42	37.7	22.6	24.0	23.9	45.1
Basis, ppmvd @ 15% O2- calculated	10	25	10	10	10	31	25	16	17	16	29
- provided (a)	10	25	10	10	10	25	25	-	-	-	-
Moisture (%)	7.92	13.11	8.44	10.62	11.08	15.81	13.96	9.40	11.65	12.08	16.73
Oxygen (%)	12.53	11.29	12.51	12.13	11.97	10.90	10.33	11.45	10.97	10.85	9.85
Volume Flow (acfm)	2,509,194	2,661,219	2,417,019	2,264,224	2,317,426	2,438,907	2,673,585	2,429,103	2,276,513	2,329,668	2,451,140
Temperature (°F)	1,088	1,108	1,102	1,133	1,126	1,125	1,108	1,102	1,133	1,126	1,125
Emission rate (lb/hr)- calculated from given ppmvd	42.4	113.7	40.0	36.3	37.7	100.4	127.3	73.3	69.7	71.0	133.7
(lb/hr)- provided	45.0	120.0	43.0	39.0	40.0	106.0	120.0	76.3	72.3	73.3	139.3
(TPY)	197.1	525.6	188.3	170.8	175.2	464.3	525.6	321.0	305.1	310.9	585.7
[Ratio lb/hr provided/calculated]	1.060	1.055	1.076	1.073	1.062	1.056	0.942	1.041	1.038	1.033	1.042
VOCs (lb/hr) = VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]											
Basis, ppmvd (as CH_4)- calculated	2.8	3.0	2.8	2.8	2.8	3.0	3.4	6.5	7.0	6.9	7.1
Basis, ppmvd @ 15% O2- calculated	2.3	2.3	2.3	2.3	2.3	2.3	2.3	4.7	4.9	4.8	4.6
- provided (a) (e)	2.3	2.3	2.3	2.3	2.3	2.3	2.3	-	-	-	-
Moisture (%)	7.92	13.11	8.44	10.62	11.08	15.81	13.96	9.40	11.65	12.08	16.73
Oxygen (%)	12.53	11.29	12.51	12.13	11.97	10.90	10.33	11.45	10.97	10.85	9.85
Volume Flow (acfm)	2,509,194	2,661,219	2,417,019	2,264,224	2,317,426	2,438,907	2,673,585	2,429,103	2,276,513	2,329,668	2,451,140
Temperature (°F)	1,088	1,108	1,102	1,133	1,126	1,125	1,108	1,102	1,133	1,126	1,125
Emission rate (lb/hr)- calculated	5.5	5.8	5.1	4.7	4.8	5.2	6.5	12.1	11.6	11.8	12.1
(lb/hr)- provided	5.8	6.2	5.4	4.9	5.1	5.5	6.2	12.4	11.9	12.1	12.4
(TPY)	25.2	26.9	23.8	21.6	22.4	23.9	26.9	52.9	50.9	51.6	53.0
[Ratio lb/hr provided/calculated]	1.056	1.052	1.056	1.056	1.056	1.056	0.939	1.024	1.023	1.023	1.024
Lead (lb/hr) = NA											
Emission Rate Basis (c)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Emission rate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
(TPY)	0	0	0	0	0	0	0	0	0	0	0
Mercury (lb/hr) = NA											
Emission Rate Basis (c)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Emission Rate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
(TPY)	0	0	0	0	0	0	0	0	0	0	0
Sulfuric Acid Mist = SO2 emission rate (lb/hr) x conversion rate of SO2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)											
SO_2 emission rate (lb/hr)	11.0	11.8	10.4	9.4	9.8	10.4	11.8	11.9	11.0	11.3	12.0
lb H_2SO_4 /lb SO_2 (98/64)	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10	10	10	10	10	10	10	10	10
Emission Rate (lb/hr)	1.69	1.81	1.59	1.44	1.50	1.59	1.81	1.83	1.68	1.73	1.83
(TPY)	7.38	7.91	6.95	6.32	6.55	6.98	7.91	7.99	7.36	7.59	8.02

Sources: (a) Siemens-Westinghouse 1999.
(b) Golder Associates Inc. 1999.
(c) EPA 2000, AP-42.
(d) For NO_x emissions, data originally provided at 25 ppmvd at 15% oxygen.
(e) For VOC emissions, data originally provided at 1.5 ppmvd at 15% oxygen.

Note: ppmvd = parts per million, volume dry; O_2 = oxygen.

Table A-3. Maximum Emissions for Hazardous Air Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 100 % Load including Power Augmentation (PA) and Duct Burner (DB)

Parameter	Ambient/Compressor Inlet Temperature					DUCT BURNER (Ambient Temperature)			
	32 °F Case 9	59 °F Case 6	95 °F Case 3	95 °F Case 2	95 °F Case 1 (PA)	59 °F Case 6 (DB)	95 °F Case 3 (DB)	95 °F Case 2 (DB)	95 °F Case 1 (DB&PA)
Hours of Operation	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,968	1,853	1,684	1,746	1,860	1,853	1,684	1,746	1,860
Duct burner	0	0	0	0	0	278	278	278	278
Total	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Ammonia (lb/hr) = Ammonia (ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 17 (mole. wgt ammonia) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]									
Basis, ppmvd @15% O_2 (a) (d)	9	9	9	9	9	9	9	9	9
Moisture (%)	7.92	8.44	10.62	11.08	15.81	9.40	11.65	12.08	16.73
Oxygen (%)	12.53	12.51	12.13	11.97	10.90	11.45	10.97	10.85	9.85
Volume Flow (acfm)	2,509,194	2,417,019	2,264,224	2,317,426	2,438,907	2,429,103	2,276,513	2,329,668	2,451,140
Temperature (°F)	1,088	1,102	1,133	1,126	1,125	1,102	1,133	1,124	1,125
Emission rate (lb/hr)	23.2	21.8	19.9	20.6	21.9	24.8	22.8	23.6	24.9
(TPY)	102	96	87	90	96	109	100	103	109
1,3- Butadiene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	4.30E-01	4.30E-01	4.30E-01	4.30E-01	4.30E-01	4.30E-01	4.30E-01	4.30E-01	4.30E-01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	8.46E-04	7.97E-04	7.24E-04	7.51E-04	8.00E-04	9.16E-04	8.43E-04	8.70E-04	9.19E-04
(TPY)	3.71E-03	3.49E-03	3.17E-03	3.29E-03	3.50E-03	4.01E-03	3.69E-03	3.81E-03	4.03E-03
Acetaldhyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	4.00E+01	4.00E+01	4.00E+01	4.00E+01	4.00E+01	4.00E+01	4.00E+01	4.00E+01	4.00E+01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	7.87E-02	7.41E-02	6.74E-02	6.98E-02	7.44E-02	8.52E-02	7.85E-02	8.09E-02	8.55E-02
(TPY)	3.45E-01	3.25E-01	2.95E-01	3.06E-01	3.26E-01	3.73E-01	3.44E-01	3.55E-01	3.75E-01
Acrolein (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	6.40E+00	6.40E+00	6.40E+00	6.40E+00	6.40E+00	6.40E+00	6.40E+00	6.40E+00	6.40E+00
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	1.26E-02	1.19E-02	1.08E-02	1.12E-02	1.19E-02	1.36E-02	1.26E-02	1.30E-02	1.37E-02
(TPY)	5.52E-02	5.19E-02	4.72E-02	4.89E-02	5.21E-02	5.97E-02	5.50E-02	5.67E-02	5.99E-02
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	1.20E+01	1.20E+01	1.20E+01	1.20E+01	1.20E+01	1.20E+01	1.20E+01	1.20E+01	1.20E+01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	2.36E-02	2.22E-02	2.02E-02	2.10E-02	2.23E-02	2.56E-02	2.35E-02	2.43E-02	2.57E-02
(TPY)	1.03E-01	9.74E-02	8.85E-02	9.18E-02	9.78E-02	1.12E-01	1.03E-01	1.06E-01	1.12E-01
Ethylbenzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	3.20E+01	3.20E+01	3.20E+01	3.20E+01	3.20E+01	3.20E+01	3.20E+01	3.20E+01	3.20E+01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	6.30E-02	5.93E-02	5.39E-02	5.59E-02	5.95E-02	6.82E-02	6.28E-02	6.48E-02	6.84E-02
(TPY)	2.76E-01	2.60E-01	2.36E-01	2.45E-01	2.61E-01	2.99E-01	2.75E-01	2.84E-01	3.00E-01
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	1.50E+02	1.50E+02	1.50E+02	1.50E+02	1.50E+02	1.50E+02	1.50E+02	1.50E+02	1.50E+02
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	2.95E-01	2.78E-01	2.53E-01	2.62E-01	2.79E-01	3.20E-01	2.94E-01	3.04E-01	3.21E-01
(TPY)	1.29E+00	1.22E+00	1.11E+00	1.15E+00	1.22E+00	1.40E+00	1.29E+00	1.33E+00	1.40E+00
Napthalene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	1.30E+00	1.30E+00	1.30E+00	1.30E+00	1.30E+00	1.30E+00	1.30E+00	1.30E+00	1.30E+00
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	2.56E-03	2.41E-03	2.19E-03	2.27E-03	2.42E-03	2.77E-03	2.55E-03	2.63E-03	2.78E-03
(TPY)	1.12E-02	1.06E-02	9.59E-03	9.94E-03	1.06E-02	1.21E-02	1.12E-02	1.15E-02	1.22E-02
Polycyclic Aromatic Hydrocarbons (PAH) (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	2.20E+00	2.20E+00	2.20E+00	2.20E+00	2.20E+00	2.20E+00	2.20E+00	2.20E+00	2.20E+00
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	4.33E-03	4.08E-03	3.70E-03	3.84E-03	4.09E-03	4.69E-03	4.32E-03	4.45E-03	4.70E-03
(TPY)	1.90E-02	1.79E-02	1.62E-02	1.68E-02	1.79E-02	2.05E-02	1.89E-02	1.95E-02	2.06E-02
Propylene Oxide (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	2.90E+01	2.90E+01	2.90E+01	2.90E+01	2.90E+01	2.90E+01	2.90E+01	2.90E+01	2.90E+01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	5.71E-02	5.37E-02	4.88E-02	5.06E-02	5.39E-02	6.18E-02	5.69E-02	5.87E-02	6.20E-02
(TPY)	2.50E-01	2.35E-01	2.14E-01	2.22E-01	2.36E-01	2.71E-01	2.49E-01	2.57E-01	2.72E-01
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	1.30E+02	1.30E+02	1.30E+02	1.30E+02	1.30E+02	1.30E+02	1.30E+02	1.30E+02	1.30E+02
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	2.56E-01	2.41E-01	2.19E-01	2.27E-01	2.42E-01	2.77E-01	2.55E-01	2.63E-01	2.78E-01
(TPY)	1.12E+00	1.06E+00	9.59E-01	9.94E-01	1.06E+00	1.21E+00	1.12E+00	1.15E+00	1.22E+00
Xylene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu									
Basis, lb/10^{12} Btu	6.40E+01	6.40E+01	6.40E+01	6.40E+01	6.40E+01	6.40E+01	6.40E+01	6.40E+01	6.40E+01
Heat Input Rate (MMBtu/hr)	1,968	1,853	1,684	1,746	1,860	2,131	1,962	2,024	2,138
Emission Rate (lb/hr)	1.26E-01	1.19E-01	1.08E-01	1.12E-01	1.19E-01	1.36E-01	1.26E-01	1.30E-01	1.37E-01
(TPY)	5.52E-01	5.19E-01	4.72E-01	4.89E-01	5.21E-01	5.97E-01	5.50E-01	5.67E-01	5.99E-01

Source: EPA, 2000, AP-42.

Table A-5. Maximum Emissions for Criteria and Other Regulated Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 75 % Load

Parameter	Ambient/Compressor Inlet Temperature 32 °F Case 10	59 °F Case 7	95 °F Case 4
Hours of Operation	8,760	8,760	8,760
<u>Particulate from CT and SCR</u>			
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer (front- and back-half)			
Basis, lb/hr - provided (a)	14.6	14.0	13.0
Particulate from SCR= Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM10)			
Particulate from conversion of SO_2= SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/ lb SO_3			
SO_2 emission rate (lb/hr)- calculated	8.6	8.1	7.6
Conversion (%) from SO_2 to SO_3	25	25	25
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
Conversion (%) from SO_3 to $(NH_4)_2(SO_4)$	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	4.42	4.19	3.89
Particulate (lb/hr) from CT + SCR	19.0	18.2	16.9
(TPY)	83.3	79.7	73.9
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100			
Fuel use (cf/hr)	1,501,214	1,423,626	1,321,928
Sulfur content (grains/ 100 cf) - assumed (b)	2	2	2
lb SO_2 /lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	8.6	8.1	7.6
(lb/hr)- provided (0.2 gr/100 cf) (not used)	0.93	0.89	0.82
(TPY)	37.6	35.6	33.1
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 (a) (d)	3.5	3.5	3.5
Moisture (%)	7.12	7.64	9.76
Oxygen (%)	13.42	13.41	13.10
Volume Flow (acfm)	2,058,955	2,005,603	1,947,155
Temperature (°F)	998	1,013	1,045
Emission rate (lb/hr)- calculated	19.0	18.0	16.7
(lb/hr)- provided	20.1	19.0	17.7
(TPY)	87.9	83.3	77.4
[Ratio lb/hr provided/calculated]	1.056	1.056	1.056
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd- calculated	10.9	10.8	10.8
Basis, ppmvd @ 15% O_2- calculated	10	10	10
- provided (a)	10	10	10
Moisture (%)	7.12	7.64	9.76
Oxygen (%)	13.42	13.41	13.10
Volume Flow (acfm)	2,058,955	2,005,603	1,947,155
Temperature (°F)	998	1,013	1,045
Emission rate (lb/hr)- calculated from given ppmv	33.0	31.3	29.1
(lb/hr)- provided	35.0	33.0	31.0
(TPY)	153.3	144.5	135.8
[Ratio lb/hr provided/calculated]	1.059	1.053	1.065
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd (as CH_4)- calculated	4.6	4.5	4.5
Basis, ppmvd @ 15% O_2- calculated	4.2	4.2	4.2
- provided (a) (e)	4.2	4.2	4.2
Moisture (%)	7.12	7.64	9.76
Oxygen (%)	13.42	13.41	13.10
Volume Flow (acfm)	2,058,955	2,005,603	1,947,155
Temperature (°F)	998	1,013	1,045
Emission rate (lb/hr)- calculated	7.9	7.5	7.0
(lb/hr)- provided	8.4	7.9	7.4
(TPY)	36.7	34.8	32.3
[Ratio lb/hr provided/calculated]	1.056	1.056	1.056
Lead (lb/hr)= NA			
Emission Rate Basis (c)	NA	NA	NA
Emission rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = NA			
Emission Rate Basis (c)	NA	NA	NA
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4 /MW SO_2 (98/64)			
SO2 emission rate (lb/hr)	8.6	8.1	7.6
lb H_2SO_4 /lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10
Emission Rate (lb/hr)	1.31	1.25	1.16
(TPY)	5.75	5.46	5.07

Source: (a) Siemens-Westinghouse 1999.
(b) Golder Associates Inc. 1999.
(c) EPA 2000, AP-42.
(d) For NOx emissions, data originally provided at 25 ppmvd at 15% oxygen.
(e) For VOC emissions, data originally provided at 2.8 ppmvd at 15% oxygen.

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Table A-6. Maximum Emissions for Hazardous Air Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 75 % Load

Parameter	Ambient/Compressor Inlet Temperature 32 °F Case 10	59 °F Case 7	95 °F Case 4
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,534	1,454	1,351
Duct burner	0	0	0
Total	1,534	1,454	1,351
Ammonia (lb/hr) = Ammonia (ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 17 (mole. wgt ammonia) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 (a) (d)	9	9	9
Moisture (%)	7.12	7.64	9.76
Oxygen (%)	13.42	13.41	13.10
Volume Flow (acfm)	2,058,955	2,005,603	1,947,155
Temperature (°F)	998	1,013	1,045
Emission rate (lb/hr)	18.1	17.1	15.9
(TPY)	79	75	70
1,3- Butadiene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.30E-01	4.30E-01	4.30E-01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	6.59E-04	6.25E-04	5.81E-04
(TPY)	2.89E-03	2.74E-03	2.54E-03
Acetalhyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.00E+01	4.00E+01	4.00E+01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	6.13E-02	5.82E-02	5.40E-02
(TPY)	2.69E-01	2.55E-01	2.37E-01
Acrolein (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	6.40E+00	6.40E+00	6.40E+00
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	9.82E-03	9.31E-03	8.64E-03
(TPY)	4.30E-02	4.08E-02	3.79E-02
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E+01	1.20E+01	1.20E+01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	1.84E-02	1.75E-02	1.62E-02
(TPY)	8.06E-02	7.64E-02	7.10E-02
Ethylbenzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	3.20E+01	3.20E+01	3.20E+01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	4.91E-02	4.65E-02	4.32E-02
(TPY)	2.15E-01	2.04E-01	1.89E-01
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.50E+02	1.50E+02	1.50E+02
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	2.30E-01	2.18E-01	2.03E-01
(TPY)	1.01E+00	9.56E-01	8.87E-01
Napthalene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.30E+00	1.30E+00	1.30E+00
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	1.99E-03	1.89E-03	1.76E-03
(TPY)	8.73E-03	8.28E-03	7.69E-03
Polycyclic Aromatic Hydrocarbons (PAH) (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	2.20E+00	2.20E+00	2.20E+00
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	3.37E-03	3.20E-03	2.97E-03
(TPY)	1.48E-02	1.40E-02	1.30E-02
Propylene Oxide (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	2.90E+01	2.90E+01	2.90E+01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	4.45E-02	4.22E-02	3.92E-02
(TPY)	1.95E-01	1.85E-01	1.72E-01
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.30E+02	1.30E+02	1.30E+02
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	1.99E-01	1.89E-01	1.76E-01
(TPY)	8.73E-01	8.28E-01	7.69E-01
Xylene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	6.40E+01	6.40E+01	6.40E+01
Heat Input Rate (MMBtu/hr)	1,534	1,454	1,351
Emission Rate (lb/hr)	9.82E-02	9.31E-02	8.64E-02
(TPY)	4.30E-01	4.08E-01	3.79E-01

Source: EPA, 2000, AP-42.

Table A-8. Maximum Emissions for Criteria and Other Regulated Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60 % Load

Parameter	Ambient/Compressor Inlet Temperature 32 °F Case 11	59 °F Case 8	95 °F Case 5
Hours of Operation	8,760	8,760	8,760
Particulate from CT and SCR			
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer (front- and back-half)			
Basis, lb/hr (a)	12.2	11.7	11.0
Particulate from SCR = Sulfur trioxide (formed from conversion of SO_2) converts to ammonium sulfate (=PM10)			
Particulate from conversion of SO_2 = SO_2 emissions (lb/hr) x Conversion SO_2 to SO_3 x lb SO_3/lb SO_2 x Conversion of SO_3 x lb SO_3 to $(NH_4)_2SO_4$ x $(NH_4)_2SO_4$/lb SO_3			
SO_2 emission rate (lb/hr)- calculated	7.4	7.2	6.5
Conversion (%) from SO_2 to SO_3	25	25	25
MW SO_3/ SO_2 (80/64)	1.3	1.3	1.3
	100	100	100
MW $(NH_4)_2SO_4$/ SO_3 (132/80)	1.7	1.7	1.7
Particulate (lb/hr)- calculated	3.84	3.69	3.35
Particulate (lb/hr) from CT + SCR	16.0	15.4	14.3
(TPY)	70.2	67.6	62.8
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2/lb S) /100			
Fuel use (cf/hr)	1,303,411	1,252,999	1,137,756
Sulfur content (grains/ 100 cf) - assumed (b)	2	2	2
lb SO_2/lb S (64/32)	2	2	2
Emission rate (lb/hr)- calculated	7.4	7.2	6.5
(lb/hr)- provided (0.2 gr/100 cf) (not used)	0.81	0.78	0.71
(TPY)	32.6	31.4	28.5
Nitrogen Oxides (lb/hr)= NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 (a) (d)	3.5	3.5	3.5
Moisture (%)	7.36	7.94	9.86
Oxygen (%)	13.15	13.07	12.99
Volume Flow (acfm)	1,817,013	1,795,882	1,703,893
Temperature (°F)	1,076	1,107	1,094
Emission rate (lb/hr)- calculated	16.5	15.9	14.4
(lb/hr)- provided	17.4	16.8	15.2
(TPY)	76.3	73.4	66.6
[Ratio lb/hr provided/calculated]	1.056	1.056	1.056
Carbon Monoxide (lb/hr)= CO(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd- calculated	56.8	56.8	55.0
Basis, ppmvd @ 15% O2- calculated	50	50	50
- provided (a)	50	50	50
Moisture (%)	7.36	7.94	9.86
Oxygen (%)	13.15	13.07	12.99
Volume Flow (acfm)	1,817,013	1,795,882	1,703,893
Temperature (°F)	1,076	1,107	1,094
Emission rate (lb/hr)- calculated from given ppmvd	143.4	137.9	125.2
(lb/hr)- provided	152.0	146.0	133.0
(TPY)	665.8	639.5	582.5
[Ratio lb/hr provided/calculated]	1.060	1.058	1.062
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/ 100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]			
Basis, ppmvd (as CH_4)- calculated	4.8	4.8	4.6
Basis, ppmvd @ 15% O2- calculated	4.2	4.2	4.2
- provided (a) (e)	4.2	4.2	4.2
Moisture (%)	7.36	7.94	9.86
Oxygen (%)	13.15	13.07	12.99
Volume Flow (acfm)	1,817,013	1,795,882	1,703,893
Temperature (°F)	1,076	1,107	1,094
Emission rate (lb/hr)- calculated	6.9	6.6	6.0
(lb/hr)- provided	7.3	7.0	6.3
(TPY)	31.8	30.6	27.8
[Ratio lb/hr provided/calculated]	1.056	1.056	1.056
Lead (lb/hr)= NA			
Emission Rate Basis (c)	NA	NA	NA
Emission rate (lb/hr)	0	0	0
(TPY)	0	0	0
Mercury (lb/hr) = NA			
Emission Rate Basis (c)	NA	NA	NA
Emission Rate (lb/hr)	0	0	0
(TPY)	0	0	0
Sulfuric Acid Mist = SO_2 emission rate (lb/hr) x conversion rate of SO_2 to H_2SO_4 (%) x MW H_2SO_4/MW SO_2 (98/64)			
SO2 emission rate (lb/hr)	7.4	7.2	6.5
lb H_2SO_4/lb SO_2 (98/64)	1.53	1.53	1.53
Conversion to H_2SO_4 (%) (b)	10	10	10
Emission Rate (lb/hr)	1.14	1.10	1.00
(TPY)	5.00	4.80	4.36

Source: (a) Siemens-Westinghouse 1999.
(b) Golder Associates Inc. 1999 .
(c) EPA 2000, AP-42.
(d) For NOx emissions, data originally provided at 25 ppmvd at 15% oxygen.
(e) For VOC emissions, data originally provided at 2.8 ppmvd at 15% oxygen.

Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Table A-9 Maximum Emissions for Hazardous Air Pollutants for the Osprey Energy Center Project
Siemens-Westinghouse 501F, Dry Low NOx Combustor, Natural Gas, 60 % Load

Parameter	Ambient/Compressor Inlet Temperature 32 °F Case 11	59 °F Case 8	95 °F Case 5
Hours of Operation	8,760	8,760	8,760
Heat Input Rate (MMBtu/hr), HHV- CT	1,332	1,280	1,162
Duct burner	0	0	0
Total	1,332	1,280	1,162
Ammonia (lb/hr) = Ammonia (ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 17 (mole. wgt ammonia) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]			
Basis, ppmvd @15% O_2 (a) (d)	9	9	9
Moisture (%)	7.36	7.94	9.86
Oxygen (%)	13.15	13.07	12.99
Volume Flow (acfm)	1,817,013	1,795,882	1,703,893
Temperature (°F)	1,076	1,107	1,094
Emission rate (lb/hr)	15.7	15.1	13.7
(TPY)	69	66	60
1,3- Butadiene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.30E-01	4.30E-01	4.30E-01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	5.73E-04	5.50E-04	5.00E-04
(TPY)	2.51E-03	2.41E-03	2.19E-03
Acetalhyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	4.00E+01	4.00E+01	4.00E+01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	5.33E-02	5.12E-02	4.65E-02
(TPY)	2.33E-01	2.24E-01	2.04E-01
Acrolein (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	6.40E+00	6.40E+00	6.40E+00
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	8.52E-03	8.19E-03	7.44E-03
(TPY)	3.73E-02	3.59E-02	3.26E-02
Benzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.20E+01	1.20E+01	1.20E+01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	1.60E-02	1.54E-02	1.39E-02
(TPY)	7.00E-02	6.73E-02	6.11E-02
Ethylbenzene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	3.20E+01	3.20E+01	3.20E+01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	4.26E-02	4.10E-02	3.72E-02
(TPY)	1.87E-01	1.79E-01	1.63E-01
Formaldehyde (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.50E+02	1.50E+02	1.50E+02
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	2.00E-01	1.92E-01	1.74E-01
(TPY)	8.75E-01	8.41E-01	7.64E-01
Napthalene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.30E+00	1.30E+00	1.30E+00
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	1.73E-03	1.66E-03	1.51E-03
(TPY)	7.58E-03	7.29E-03	6.62E-03
Polycyclic Aromatic Hydrocarbons (PAH) (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	2.20E+00	2.20E+00	2.20E+00
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	2.93E-03	2.82E-03	2.56E-03
(TPY)	1.28E-02	1.23E-02	1.12E-02
Propylene Oxide (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	2.90E+01	2.90E+01	2.90E+01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	3.86E-02	3.71E-02	3.37E-02
(TPY)	1.69E-01	1.63E-01	1.48E-01
Toluene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	1.30E+02	1.30E+02	1.30E+02
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	1.73E-01	1.66E-01	1.51E-01
(TPY)	7.58E-01	7.29E-01	6.62E-01
Xylene (lb/hr) = Basis (lb/10^{12} Btu) x Heat Input (MMBtu/hr) / 1,000,000 MMBtu/10^{12} Btu			
Basis, lb/10^{12} Btu	6.40E+01	6.40E+01	6.40E+01
Heat Input Rate (MMBtu/hr)	1,332	1,280	1,162
Emission Rate (lb/hr)	8.52E-02	8.19E-02	7.44E-02
(TPY)	3.73E-01	3.59E-01	3.26E-01

Source: EPA, 2000, AP-42.

Table B-3a. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the Siemens Westinghouse 501FD Combined Cycle Combustion Turbine

Cost Component	Costs for SCR	Costs for SCONOx™		Basis of Cost Component
Direct Capital Costs				
Pollution Control Equipment	$1,418,000	$16,712,000		Vendor Estimates
Ammonia Storage Tank	$137,529	$0	$35	per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725		Vatavauk,1990
Instrumentation	$50,000	$50,000		Additional NO_x Monitor and System
Taxes	$85,080	$1,002,720	6%	of SCR Associated Equipment and Catalyst
Freight	$70,900	$835,600	5%	of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,806,014	$18,670,045		
Direct Installation Costs				
Foundation and supports	$144,481	1,493,604	8%	of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$252,842	2,613,806	14%	of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$72,241	746,802	4%	of TDCC and RCC;OAQPS Cost Control Manual
Piping	$36,120	373,401	2%	of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$18,060	186,700	1%	of TDCC and RCC;OAQPS Cost Control Manual
Painting	$18,060	186,700	1%	of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000		Engineering Estimate
Buildings	$15,000	$15,000		Engineering Estimate
Total Direct Installation Costs (TDIC)	$561,804	$5,621,014		
Total Capital Costs (TCC)	$2,367,819	$24,291,059		Sum of TDCC, TDIC and RCC
Indirect Costs				
Engineering	$180,601	$1,867,005	10%	of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0		Engineering Estimate
Construction and Field Expense	$90,301	$933,502	5%	of TDCC; OAQPS Cost Control Manual
Contractor Fees	$180,601	$1,867,005	10%	of TDCC; OAQPS Cost Control Manual
Start-up	$36,120	$373,401	2%	of TDCC; OAQPS Cost Control Manual
Performance Tests	$18,060	$186,700	1%	of TDCC; OAQPS Cost Control Manual
Contingencies	$54,180	$560,101	3%	of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$609,864	$5,787,714		
Total Direct, Indirect and Capital Costs (TDICC)	$2,977,683	$30,078,773		Sum of TCC and TInCC

Table B-4a. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the Siemens-Westinghouse 501FD Combined Cycle Operation

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$291,393	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$34,404	$68,808	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 2 times SCR
Catalyst Cost	$313,333	$470,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$20,270	$17,456	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$695,928	$599,320	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$336,358	$840,894	0.3% or 0.54 MW output for SCR; 0.75% or 1.35 MW for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$705,663	18,184 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$49,347	81 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$364,390	$1,665,984	
Indirect Annual Costs			
Overhead	187,752	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	29,777	300,788	1% of Total Capital Costs
Insurance	29,777	300,788	1% of Total Capital Costs
Annualized Total Direct Capital	326,950	3,302,649	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$574,256	$3,930,058	
Total Annualized Costs	$1,634,573	$6,195,362	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$2,443	$9,261	per ton of NO_x Removed
	669.01	669.01	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

RECEIVED
JUL 13 2000
BUREAU OF AIR REGULATION

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.,

Petitioner,

vs.

DEPARTMENT OF ENVIRONMENTAL PROTECTION,

Respondent.

DEP Draft Permit No. PA 00-41(PSD-FL-287)

CALPINE'S SECOND REQUEST FOR EXTENSION OF TIME TO FILE PETITION

Petitioner, Calpine Construction Finance Company, L.P. ("Calpine"), pursuant to Rule 28-106.111(3), Florida Administrative Code, respectfully requests the Department of Environmental Protection ("Department") to grant Calpine an additional extension of time to file a petition for a formal administrative hearing concerning the Department's draft permit for Calpine's Osprey Energy Center (DEP Draft Permit No. PA 00-41(PSD-FL-287)) (the "Draft Permit"). In support of this request, Calpine says:

1. On March 16, 2000 Calpine filed an application with the Department for a prevention of significant deterioration ("PSD") permit for Calpine's Osprey Energy Center, a 527 MW electrical power plant to be located at 1501 Derby Avenue, Auburndale, Florida.

2. On May 11, 2000, the Department distributed its "Public

Notice of Intent to Issue PSD Permit", Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination for the Osprey Energy Center. As the applicant for the Draft Permit, Calpine is affected by the Department's proposed action.

3. On May 23, 2000, Calpine requested a 45-day extension of time to file its petition. The Department has not yet issued an order concerning Calpine's request for extension of time.

4. The Draft Permit is lengthy and complex. Calpine's preliminary review of the Draft Permit indicated that some provisions of the Draft Permit are not consistent with Calpine's application. On June 29, 2000, representatives of Calpine met with Department staff to discuss modifications to the Draft Permit. Based on those discussions with Department staff, Calpine will submit written comments concerning the Draft Permit to the Department.

5. Although Calpine does not expect to file a petition for a formal administrative hearing concerning the Draft Permit, Calpine requests a 60-day extension of time to finalize its comments concerning the Draft Permit, and to conduct additional meetings with the Department, before Calpine waives its right to a hearing.

6. Petitioner's counsel has discussed this request with Department's counsel, Mr. Scott Goorland. Mr. Goorland indicated that the Department has not yet formulated a position concerning

this request.

WHEREFORE, Calpine requests the Department to grant a 60-day extension of time to file a petition for a formal administrative hearing concerning the Draft Permit.

Respectfully submitted this 7th day of July, 2000.

LANDERS & PARSONS

DAVID S. DEE
Fla. Bar No. 281999
JOHN T. LaVIA, III
Fla. Bar No. 853666
310 West College Avenue (32301)
P.O. Box 271
Tallahassee, Florida 32302
850/681-0311
850/224-5595 (fax)

COUNSEL FOR CALPINE CONSTRUCTION
FINANCE COMPANY, L.P.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that an original and one copy of the foregoing was furnished by hand-delivery to the CLERK'S OFFICE, Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Blvd., Room 659E, Tallahassee, Florida 32399; and a copy by U.S. Mail to Scott Goorland, Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399, on this 7th day of July, 2000.

ATTORNEY

STATE OF FLORIDA
DIVISION OF ADMINISTRATIVE HEARINGS

IN RE: CALPINE CONSTRUCTION FINANCE COMPANY, L.P. (OSPREY ENERGY CENTER); POWER PLANT SITING APPLICATION NO. PA00-41 /

DOAH CASE NO. 00-1288EPP
OGC CASE NO. 00-0740

CALPINE'S SUPPLEMENTAL RESPONSE TO DEP'S NOTICE OF INSUFFICIENCY

Calpine Construction Finance Company, L.P. (Calpine), submits this supplemental response to the notice of insufficiency (Notice) served by the Florida Department of Environmental Protection (Department or DEP) and says:

1. On March 20, 2000, Calpine filed an application for certification of an electrical power plant (the Osprey Energy Center) pursuant to the Florida Electrical Power Plant Siting Act (Act), Section 403.501, et seq. On May 22, 2000, the Department issued its Notice, which indicates that Calpine's application is "insufficient" because the application does not contain all of the information needed by the Southwest Florida Water Management District (SWFWMD) for the SWFWMD's evaluation of the Osprey Energy Center.

2. The Department's Notice indicates that Calpine may pursue several different options under the Act. Under one option, Calpine may submit additional information to the Department within 40 days to make the application sufficient. Under another option, Calpine may advise the Department and the

Administrative Law Judge that Calpine cannot submit the additional information needed to make the application sufficient within 40 days.

3. On May 26, 2000, Calpine filed a response to DEP's Notice stating that Calpine intended to submit additional information to make its application sufficient within 40 days.

4. Since filing its response to DEP's Notice, Calpine has diligently worked on assembling the additional information requested by the Department and the SWFWMD. On June 13, 2000, Calpine's consultants met with the SWFWMD staff to discuss the issues raised in DEP's Notice. In light of the discussions with SWFWMD staff, Calpine has determined that it requires more time to submit the additional information requested in DEP's Notice.

4. Accordingly, pursuant to Section 403.5067(1)(b), Florida Statutes, Calpine hereby advises the Department and the Administrative Law Judge that Calpine requires more time to submit the additional information requested in DEP's Notice. Calpine anticipates that it will submit the additional information within 45 days of this response.

Respectfully submitted this 7th day of July, 2000.

LANDERS & PARSONS

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Phone: 850/681-0311
Fax: 850/224-5595

CERTIFICATE OF SERVICE

I CERTIFY that a true and correct copy of the foregoing has been sent by U.S. Mail to the following this 7th day of July, 2000.

Steven Palmer, P.E.
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, FL 32399-3000

Scott Goorland
Senior Assistant General Counsel
Office of General Counsel
Department of Environmental Protection
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Cari Roth, General Counsel
Andrew Grayson, Asst. Gen. Coun.
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Department of Community Affairs
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City of Auburndale
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Auburndale, FL 33823

ATTORNEY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

JUN 21 2000

RECEIVED
JUN 26 2000
BUREAU OF AIR REGULATION

4APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and draft PSD Permit for Calpine Construction & Finance Company, L.P. - Osprey Energy Center in Polk County located near Auburndale, FL

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for the Osprey Energy Center dated May 10, 2000. The draft PSD permit is for the proposed construction and operation of two combined cycle combustion turbines (CTs) and two natural gas-fired heat recovery steam generating units with a total nominal generating capacity of 527 megawatts (MW). The combustion turbines proposed for the facility are Siemens Westinghouse 501FD units. The CTs will combust pipeline quality natural gas only. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2) and particulate matter (PM/PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we have the following comments:

1. In November 1999, ABB ALSTOM POWER announced the availability of SCONOx™ systems for any size combustion turbine. Region 4 therefore considers this control method technically feasible for Osprey's combined cycle CTs. Accordingly, FDEP should require the Osprey Energy Center to provide a project-specific BACT analysis for SCONOx™ (economics, environmental impacts, and energy use) before issuing a final permit.

2. We suggest you verify the emission rate used by Golder Associates to estimate potential formaldehyde emissions. The emission factor cited by Golder is only one-fifth of the emission factor cited for formaldehyde from natural gas turbines in the recently revised section 3.1 of AP-42.

3. The "Public Notice of Intent to Issue PSD Permit" indicates that the combustion turbines for this project will be General Electric PG7241FA units. It is our understanding, as

indicated elsewhere in the preliminary determination and draft PSD permit, that the Osprey Energy Center will be installing Siemens Westinghouse 501FD combustion turbines. If possible, clarify this inconsistency before the public notice is published.

Thank you for the opportunity to comment on the preliminary determination and draft PSD permit for Calpine's Osprey Energy Center. If you have any questions or concerns, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Paul Wagner

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: M. Halpin
C. Halladay
NPS
B. Owen
SWD