PSD REPORT

AIR CONSTRUCTION PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR FPL GLADES POWER PARK GLADES COUNTY, FLORIDA

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LIST OF ACRONYMS

8GL60	Indian Mountain
AAQS	Ambient Air Quality Standards
ac-ft	acre per foot
ACOE	Army Corps of Engineers
ANSI	American National Standard Institute
AQRV	Air Quality Related Values
AVT	All-volatile Internal Treatment
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BSA	byproduct storage area
CAA	Clean Air Act
CEM	Continuous Emission Monitoring
CERP	Comprehensive Everglades Restoration Project
cfs	cubic feet per second
Cl^-	chloride
CMA	Christian Migrant Association
CO	carbon monoxide
CRM	Cultural Resource Management
CSX	CSX Transportations, Inc.
CTEMISS	Cooling Tower Emissions Processor
CWA	Clean Water Act
DAT	Deposition Analysis Thresholds
dB	decibels
dBA	A-weighting decibel
DSM	Demand Side Management
EDTA	Ethylene Diamine Tetra-acetic Acid
ENR	Everglades Nutrient Removal.
EPA	Environmental Protection Agency
eq/ha	equivalents per hectare
F.A.C.	Florida Administrative Code
FADS	Florida Acid Deposition Study
FAS	Florida Aquifer System
FCREPA	Florida Committee on Rare and Endangered Plants and Animals
FDACS	Florida Department of Agriculture and Consumer Services
FDEP	Florida Department of Environmental Protection
FDOT	Florida Department of Transportation
FECWMA	Fisheating Creek Wildlife Management Area
FEMA	Federal Emergency Management Agency
FFWCC	Florida Fish and Wildlife Conservation
FGD	flue gas desulfurization
FGPP	FPL Glades Power Park (the Project)
FLM	Federal Land Manager
FLUCFCS	Florida Land Use, Cover and Forms Classification System
FMSF	Florida Master Site File
FNAI	Florida Natural Area Inventory
FPL	Florida Power & Light Company (the Company)
FPSC	Florida Public Service Commission
FR	Federal Register
FSA	Florida Statistical Abstract
ft	feet

LIST OF ACRONYMS

ft/day	feet per day
ft/day/ft	feet per day per foot
ft/year	feet per year
ft^2/day	square feet
ft-bgs	feet below ground surface
ft-bpl	feet below pad level
gpd	gallons per day
gpm	gallons per month
HAP	hazardous air pollutants
HRMC	Hendry Regional Medical Center
HSH	highest, second highest
HUD	Housing and Urban Development
Hz	hertz
IAS	intermediate aquifer system
IRP	Integrated Resource Planning
ISCST	Industrial Source Complex Short-term
kg	kilogram
kg/ha/yr	kilograms per hectare per year
kg/km^2-month	kilograms per square kilometer per month
km	kilometers
kV	kiloVolt
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
L_{eq}	equivalent sound pressure level averaged for the sampling period
LNB	low-nitrogen burners
LNG	liquefied natural gas
LOLP	loss of load probability
L_w	sound power levels
LWCPA	Lower West Coast Water Supply Plan
MDN	mecury deposition network
mg/L	milligrams per liter
mgd	million gallons per day
Mgd	million gallons per day
mi^2	square miles
MMBtu/hr	million British units per hour
MW	megawatts
MW-hr	megawatt per hour
Na^+	sodium
NGVD	National Geodetic Vertical Datum
NO^2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NP	National Park
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NWS	National Weather System
O^3	ozone
°F	Fahrenheit
OFA	overfire air

LIST OF ACRONYMS

OT	oxygenate treatment
OUA	Open Use Agriculture
Pb	lead
PM_{10}	particulate matter with aerodynamic size less than 10 microns
POR	period of record
POTW	publicly owned treatment works
ppm	parts per million
PPSA	Power Plant Siting Act
PSD	prevention of significant deterioration
PWPS	process water pretreatment system
PWTS	process water treatment system
QA	quality assurance
QC	quality control
RO	reverse osmosis
ROW	right of way
rpm	revolutions per minute
SAM	sulfuric acid mist
SAS	Superficial Aquifer System
SCA	Site Certification Application
SCFE	South Central Florida Express Railroad
SCR	selective catalytic reduction
SCRAM	Support Center for Regulatory Air Models
SFWMD	South Florida Water Management District
SIP	State Implementation Plan
SJRPP	St. Johns River Power Park
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_x	sulfur oxides
SPL	sound pressure level
TDS	total dissolved solids
TPH	tons per hour
TPY	tons per year
UFA	Upper Floridan Aquifer
$\mu g/m^2/yr$	micrograms per square meter per year
$\mu g/m^3$	micrograms per cubic meter
UIC	Underground Injection Control
μPa	micropascals
USDW	Underground Source of Drinking Water
USFWS	U.S. Fish and Wildlife Service
VISTAS	Visibility Improvement State and Tribal Association of the Southeast
VOC	volatile organic compounds
WESP	Wet Electrostatic Precipitator
WSE	water supply environment

1.0 INTRODUCTION

Florida Power & Light Company (FPL), proposes to license, construct, and operate two nominal 980-megawatt (MW) net solid fuel fired units on a 4,900-acre Site located in unincorporated Glades County, Florida (Figure 1-1). The FPL Glades Power Park (FGPP) will utilize coal and co-fire up to 20-percent (by weight) petroleum coke with coal. Each unit will consist of an ultra-supercritical pulverized coal-fired boiler, steam turbine generator, and mechanical draft-cooling tower. The term "supercritical" in the context of a boiler refers to higher steam operating pressures and temperatures [i.e., greater than 3,608 pounds per square inch (psi) and 1,100 degrees Fahrenheit (°F)] than conventional (subcritical) boiler designs and results in much greater efficiency. The air pollution control equipment will consist of selective catalytic reduction (SCR), fabric filter for particulate control, wet limestone flue gas desulfurization (FGD), a wet electrostatic precipitator (WESP), and sorbent injection for enhanced mercury control. Associated facilities for handling coal, ammonia, limestone, bottom ash, fly ash and FGD byproduct (gypsum) will be constructed. Steam will be generated by an ultra-supercritical pulverized coal-fired boiler and electricity will be produced in a generator driven by a condensing-steam turbine with reheat and extraction for feedwater heating. Each power boiler is designed to burn eastern United States (U.S.) and imported bituminous coals and petroleum coke as a co-fired fuel. Distillate oil will be used as a startup fuel and for combustion stabilization.

Fuel, limestone, distillate oil, and ammonia will be received by train delivery system. Onsite fuel storage will be able to accommodate up to 60 days of full-load operation for both units. The solid by-products generated from the combustion process (fly ash, bottom ash, and FGD by-product) will be recycled to the greatest extent possible or stored onsite.

Each power boiler will have pulverizers capable of handling the design fuel feed rate of about 400 tons per hour (TPH) or an equivalent heat input of approximately 8,700 million British thermal units per hour (MMBtu/hr). The steam generator will be capable of producing high-pressure superheated steam at an output rate of approximately 6.6 million pounds per hour (lb/hr). The steam will drive a 3,600-revolutions-per-minute (rpm) steam turbine with a hydrogen-cooled generator. The electric generator associated with the steam turbine is capable of converting the steam input rate into about 1,060-MW gross electrical power output per unit. A portion of this output will be utilized to operate the plant, resulting in the nominal net output of each unit of approximately 980 MW net.

The permitting of FGPP requires an Air Construction Permit and Prevention of Significant Deterioration (PSD) review. PSD review requires air quality assessments for determining the facility's compliance with state new source review (NSR) regulations, including addressing applicable PSD and nonattainment review requirements. The critical aspects of these assessments include the air quality impact analyses performed using appropriate air dispersion models and the Best Available Control Technology (BACT) analyses performed to evaluate the selected emission control technology.

FGPP will be a new major facility that will result in net increases in air emissions. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review for new sources that increase air emissions above certain threshold amounts. The threshold amount applicable to FGPP is 100 tons per year (TPY) for fossil fuel fired steam electric generators. Emissions from FGPP will exceed this threshold, and FGPP is subject to PSD review. Florida's PSD regulations are codified in Rule 62-212.400, Florida Administrative Code (F.A.C.), and have been approved by EPA. These Florida PSD regulations incorporate the requirements of EPA's PSD regulations.

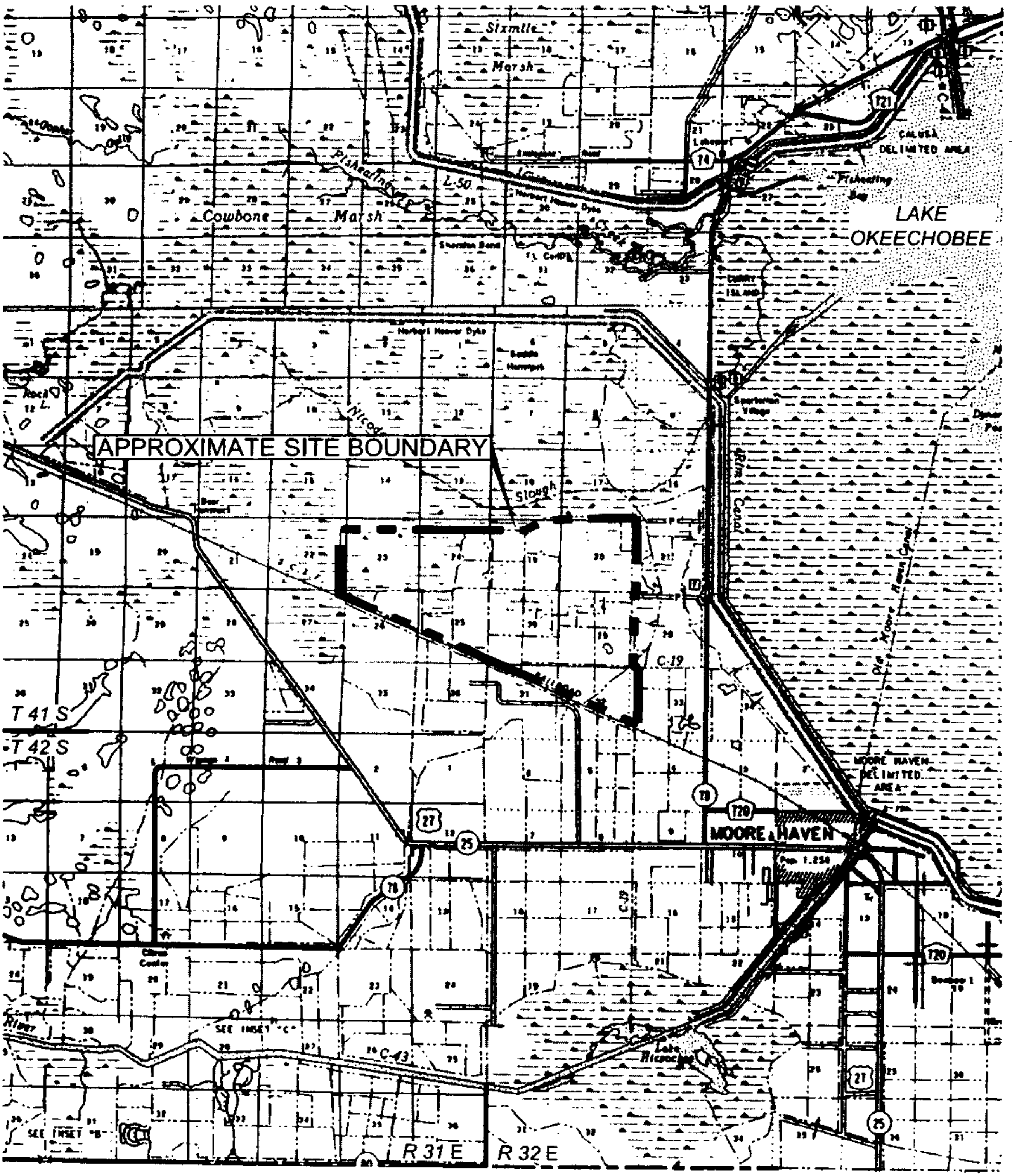
Based on the emissions from the facility for each regulated pollutant, PSD review is required for each of the following pollutants:

- Particulate matter (PM) as total suspended particulate matter (TSP) [PM(TSP)],
- Particulate matter with aerodynamic diameter of 10 microns or less (PM_{10}),
- Nitrogen dioxide (NO_2),
- Sulfur dioxide (SO_2),
- Carbon monoxide (CO),
- Volatile organic compounds (VOCs),
- Sulfuric acid mist (SAM), and
- Fluorides.

Glades County has been designated as an attainment area for all criteria pollutants [i.e., attainment: ozone (O_3), PM_{10}, SO_2, CO, and NO_2; unclassifiable: lead] and is a PSD Class II area for PM_{10}, SO_2, and NO_2; therefore, the PSD review will follow the NSR applicable to attainment areas.

The air permit application is divided into seven major sections:

- Section 2.0 presents a description of FGPP, including air emissions and stack parameters.
- Section 3.0 provides a review of the PSD and nonattainment requirements applicable to FGPP.
- Section 4.0 includes the control technology review with discussions on BACT.
- Section 5.0 discusses the ambient air monitoring analysis (pre-construction monitoring) required by PSD regulations.
- Section 6.0 presents a summary of the air modeling approach and results used in assessing compliance of the FGPP with ambient air quality standards (AAQS), and PSD increments.
- Section 7.0 provides the additional impact analyses for soils, vegetation, and visibility.



LEGEND

— — — —

APPROXIMATE SITE BOUNDARY

0 1 2

SCALE: 1" = 2 Miles

SOURCE: FDOT General Highway Map, February 1999; Golder, 2006.

REV	DATE	DES	REVISION DESCRIPTION	CADD	CHK	RVW
0	-	XXX	REV_DESC	XXX		

PROJECT

FLP GLADES POWER PARK
GLADES COUNTY, FLORIDA

TITLE

SITE LOCATION MAP

Golder Associates
Tampa, Florida

PROJECT No.		063-9524	FILE No. 0637567a015.dwg	
DESIGN	KT	7/10/06	SCALE AS SHOWN	REV. 0
CADD	KT	7/10/06		
CHECK	RAZ	7/10/06	FIGURE 1-1	
REVIEW	RAZ	7/10/06		

Drawing file: F:\PROJECTS\2006 PROJ\063-7567 FPL ATCP 2006\Glades VIA\CAD FILES\0637567a015.dwg Dec 08, 2006 - 12:18pm

2.0 PROJECT DESCRIPTION

2.1 SITE LAYOUT AND DESCRIPTION

FGPP will be located within a 4,900-acre Site, with the power block and fuel and limestone handling facilities located in the central portion of the Site and the by-product storage facilities located toward the northeast. Figure 2-1 present the boundary of the Site. Figure 2-2 presents an overall plot plan with Figures 2-3 and 2-4 providing greater detail of the facilities. A typical profile of the facilities is shown in Figure 2-5. Approximately 65 acres will be utilized for the power block containing the ultra-supercritical boilers, steam turbine/electric generators, cooling towers, and other facilities.

2.2 FUELS

The primary fuel will be eastern U.S. and imported bituminous coals, and petroleum coke, delivered to the plant by rail. The units will co-fire up to 20 percent by weight petroleum coke with coals. The amounts of each type of fuel will vary depending upon economic conditions. Typical ultimate and proximate analyses of coals and petroleum coke representative of the types of fuels proposed for FGPP are shown in Table 2-1. Distillate oil with a sulfur content not to exceed 0.0015 percent will be used for startup (Table 2-2).

Maximum hourly fuel use quantities representative of full load operation for typical fuels will range from about 350 to 400 TPH for each unit. On average, maximum annual fuel use will be about 6.7 million TPY. The TPY is based on 100-percent capacity factor. The active fuel storage area will contain sufficient fuel for about 7 days of operation, while the inactive storage area will contain sufficient fuel for up to 60 days of operation for both units.

2.3 SOURCE EMISSIONS AND STACK PARAMETERS

The types and sources of air emissions associated with FGPP consist of the two ultra-supercritical boilers, two mechanical draft-cooling towers, two emergency generators, one auxiliary boiler, and material handling facilities.

State-of-the-art air pollution handling equipment will be installed on FGPP to minimize air emissions. Within the boiler, combustion controls will minimize the formation of nitrogen oxides (NO_x) and the formation of CO and VOCs by combustor design. After the economizer, further NO_x reduction will be achieved by SCR. PM emissions will be controlled using a fabric filter commonly referred to as a baghouse. An electro-static precipitator (ESP) may be installed prior to the fabric filter as a means to remove ash for by-product recycling. Sulfur oxides (SO_x) will be controlled using a wet limestone FGD followed by a WESP. The combination of these techniques are proposed for FGPP and have been determined to represent BACT on previous projects based on an evaluation of economic, energy, and environmental impacts. Table 2-3 presents the performance and maximum estimated emission rates of regulated pollutants for each nominal 980-MW supercritical unit. The design parameters are provided in Table 2-3 for operating loads of 100, 70, and 40 percent. The maximum estimated emission rates were determined using the air pollution control equipment proposed for FGPP.

Emissions of pollutants classified as hazardous air pollutants (HAPs) will result from metals found in trace amounts in coal and petroleum coke. Certain trace metals can also be volatilized in the combustion process. These trace metals either remain in the gas phase or condense to form small PM. The fraction that condenses is dependent upon the specific trace metal and the flue gas temperature. Some trace metals condense onto other PM in the gas stream and may be collected in the particulate control system. The amount of condensation depends upon the volatilization properties of the trace metals and the temperature prior to the particulate control device. The combination of controls that include a fabric filter, wet FGD, and WESP will effectively limit the emissions of these pollutants.

For mercury, removal is enhanced by the SCR where elemental mercury is oxidized into a form that can be readily collected by the fabric filter, wet FGD system, and WESP. Sorbent injection will be used to provide additional mercury control. The sorbent, which will be injected as a fine powder, will enhance mercury removal from the gas stream as well as provide continued sorption while the sorbent remains on the filters. A mercury emission rate of 9.9×10^{-6} pounds per megawatt per hour (lb/MW-hr) on an annual basis is proposed. This emission level is less than one-half of the U.S. Environmental Protection Agency (EPA) mercury emission limit of 20×10^{-6} lb/MW-hr for new bituminous coal-fired power plants [Code of Federal Regulations, Title 40 (40 CFR) 60.45a; EPA, 2006]. Emissions of lead are effectively controlled by the fabric filter, as the primary PM control device, and the WESP, which will remove additional lead-containing particles. Hydrogen fluoride will be effectively removed in the wet limestone FGD at removal levels similar to that of SO_2 (e.g., 98 perecent). Organic HAP emissions are controlled by boiler design features and combustion air feed rates. The boilers will be designed and operated for high-combustion efficiency, which will inherently minimize the production of organic HAP emissions.

Emissions for HAPs were determined based on the revised AP-42 emission factors. For metals, AP-42 emission factors were used along with data available from the U.S. Geological Survey (USGS) on coal quality. The use of AP-42 emission factors for HAPs is considered to provide conservative estimates of emissions. The estimated HAP emissions for FGPP based on AP-42 emission factors and conservative assumptions on fuel quality are presented in Appendix A.

The mercury emissions for FGPP were based on an evaluation of the potential mercury concentrations in the fuels being considered and the co-benefits of the air quality control system that includes SCR, fabric filter, wet limestone FGD, and WESP. In addition, sorbent injection would be used to further reduce mercury. Together, 90-percent removal was considered technically feasible with the combination of controls. FGPP will use a variety of fuel supplies that includes coal from Central Appalachia, imported bituminous coals, and petroleum coke. Central Appalachian coal was used as the basis for determining the uncontrolled mercury content. The U.S. Geological Survey (USGS) COALQUAL database was used to determine the expected annual average mercury content in the coal. An uncontrolled emission rate of about 12 pounds per trillion Btu (lb/TBtu) was determined using both the average of all Central Appalachian coals in the USGS COALQUAL database. Mercury content in coal is quite variable and varies by area and mine, and the data clearly suggests a lognormal distribution. Using the average mercury concentration provides an appropriate basis for an uncontrolled mercury concentration in the coals for FGPP that would be expected over an annual period. Using 90-percent control and an uncontrolled an emission rate of 12 lb/TBtu, an annual average emission limit of 9.9×10^{-6} lb/MW-hr is being proposed for FGPP. The EPA Subpart Da mercury standard is an annual average and the monitoring requirements for this standard will be used to demonstrate compliance.

Table 2-4 presents the potential PM/PM_{10} emissions from the mechanical draft-cooling tower associated with each 980-MW unit. PM emissions are emitted from a mechanical draft-cooling tower in the form of drift. Drift is water aerosols emitted from the cooling tower containing dissolved minerals from the water circulating in the cooling tower. The dissolved minerals become PM including PM_{10} when the water in the drift is evaporated. Cooling tower drift will be controlled through the use of mist eliminators that will be designed to limit drift to 0.0005 percent of the circulating water rate of the cooling tower.

PM emissions will be generated by material handling operations that include fuel handing and storage, limestone handling and storage, and by-product handling and storage. The latter includes bottom and fly ash and FGD by-product.

Fuel (domestic and imported bituminous coals and petroleum coke) will be transported to the Site by rail in up to 125-car unit trains. On average, about one train per day will deliver fuel to the Site. Fuel will be unloaded in rapid rail unloading system with dust control. From the unloading system, the fuel will be transferred to a transfer tower where fuel is unloaded into the active and inactive storage areas using a portal unloading system. The active coal storage area will maintain sufficient fuel for about 7 days of full-load operation by both units, while the inactive storage area will maintain sufficient fuel for up to 60 days of full-load operation by both units. The inactive fuel storage area will be sealed with a crusting agent. The fuel will be reclaimed from the pile and conveyed to an enclosed crusher tower. After crushing, the fuel is then conveyed through an enclosed tripper house to the storage silos adjacent to the boilers. Bulldozers and/or front-end loaders are used for reclaim and pile maintenance, as necessary.

Figure 2-6 presents a conceptual flow diagram of the fuel handling system. This arrangement may be altered during detailed design. The facilities shown in the flow diagram envelope possible alternate designs so that emissions from dust collection systems, transfer points, and other operations (e.g., storage) will be no greater in aggregate than those identified in this chapter.

Limestone used in the wet FGD system will be transported to the Site by rail. Rail delivery of limestone will be in approximately 40-car trains with delivery about five to six times per month. Limestone will be unloaded using a bottom-dump system. From the bottom-dump system, the limestone will be transferred to a storage pile. About 60 days storage will be maintained for the operation of the units. The limestone will be reclaimed from the pile using a reclaim system and conveyed to day bins. Bulldozers and/or front-end loaders will be used as necessary for reclaim and storage pile maintenance. Figure 2-7 presents a flow diagram of limestone handling.

Bottom ash from the boilers will be collected and directed to the storage bunkers. Either a wet or dry bottom ash system will be used. The wet bottom ash system will be collect bottom ash using a submerged conveyor and sluiced to the storage bunkers. From the bunkers, the bottom ash is transported by truck to the by-product storage area or transported offsite for use as an aggregate.

Economizer ash and fly ash from the air heaters and fabric filters will be pneumatically conveyed to storage silos. Fly ash that is recycled for cement or other purposes, will be transported offsite in enclosed tanker trucks or rail cars. Any fly ash stored in the by-product storage area will be mixed with water (e.g., pug mill), unloaded into covered trucks, and transported to the onsite byproduct disposal area. After dewatering, FGD byproduct (gypsum) will be conveyed to a storage shed. Front-end loaders will be used for bottom ash and gypsum loading. Figure 2-8 presents a conceptual flow diagram of ash and FGD by-product handling.

The dry bottom ash system will continuously collect dry bottom ash in a hopper located directly beneath each boiler. The dry bottom ash will be removed from the boiler using either an enclosed air-cooled dry scraper conveyor or a vibrating conveyor (see Figure 2-9). The bottom ash would be passed through a crusher and forwarded into a bottom ash bin located adjacent to the boiler. Bottom ash would then be pneumatically transported to a bottom ash storage silo. The dry bottom ash would be unloaded from the silo into enclosed bulk transport trucks for sale as aggregate or for transport to the byproduct storage area. In the event of a crusher failure, an emergency chute would be provided to direct bottom ash into a bunker or truck at grade for disposal in the byproduct storage area or staged for recycling. This system negates the requirement for the water cooling and sealing of the bottom ash hopper. All components are air cooled and the seal between the bottom ash hopper and the boiler is maintained using an expansion joint. The contents of the dewatering bins would be periodically dewatered and transported to the by-product storage area. One dewatering bin would be in operation while the other is being dewatered and/or emptied.

Fugitive emission factors for the various material handling operations were estimated in accordance with current EPA techniques as presented in AP-42, Compilation of Air Pollutant Emission Factors (EPA, 2006), fugitive dust background document (EPA, 1992), historical EPA emission factors, and equipment design information. Fugitive emissions were estimated for batch drop operations, wind erosion, coal pile maintenance, and dust collection systems.

For batch drop operations, the total suspended particulate matter [PM(TSP)] and PM_{10} emission factors for batch drop operations are defined in Section 13.2.4 of AP-42 by the equation:

$$E = k(0.0032)\,(U/5)^{1.3}/(M/2)^{1.4}\ \text{lb/ton}$$

where: E = emission factor, lb/ton;
k = particle size multiplier;
U = mean wind speed [miles per hour (mph)]; and
M = material moisture content (percent).

The particle size multiplier, k, was based on the EPA multipliers of 0.74 and 0.35 in developing the PM(TSP) and PM_{10} emission estimates, respectively. Mean and maximum daily wind speeds were obtained from the Local Climatological Data and hourly data from Fort Myers Airport. The mean annual wind speed used to calculate emissions was 6.9 mph and the maximum daily wind speed used was 11 mph. Moisture contents for fuel, limestone, fly and bottom ash, and gypsum used to calculate emissions were 6.45, 2, 20, and 10 percent, respectively. The moisture content for fuel was obtained from the fuel analyses of the representative fuels proposed for FGPP. AP-42 was used as the moisture content for limestone. Fly ash that is transported to the byproduct storage area will contain moisture from the pug mill. Bottom ash is collected in a submerged conveyor. Gypsum from the FGD system has a high-moisture content.

For emissions from wind erosion of active (frequently disturbed) storage piles, the PM(TSP) and PM_{10} emission factors from continuously active piles, derived from Section 2.3.1.3.3 in EPA's fugitive dust background document, are:

$$E = k(1.7)(s/1.5)[(365-p)/235](f/15)\ \text{(lb/day/acre)}$$

where: E = emission factor (lb/day/acre),
k = particle size multiplier,
s = silt content of aggregate (percent),
p = number of days with at least 0.01 inch of precipitation per year, and
f = percent of time that unobstructed wind speed exceeds 12 mph at the mean pile height.

The particle size multiplier, k, was based on the EPA multipliers of 1.0 and 0.50 in developing the PM(TSP) and PM_{10} emission estimates, respectively. The coal silt content was assumed to be 2.2 percent, based on typical silt contents associated with coal-fired power generation sources identified in Table 13.2.4-1 of AP-42; the mean silt content is 2.2. The silt content for limestone and gypsum was 1.6 percent based on AP-42. For annual average emissions, the number of days with at least 0.01 inch of precipitation per year was 113, based on data collected at Fort Myers Airport. The annual frequency of wind speed greater than 12 mph [5.4 meters per second (m/s)] was 13 percent based on an evaluation of hourly meteorological data.

The PM(TSP) and PM_{10} emission factors for active coal pile maintenance, derived from Section 13.2.2 in AP-42, are:

$$E = k(5.9)(s/12)^{a} (W/3)^{b} [(365\text{-}p)/365](\text{lb/vehicle mile traveled})$$

where: E = emission factor (lb/vehicle mile traveled),
k = particle size multiplier,
a,b = particle size exponents,
s = silt content of surface material (percent),
W = mean vehicle weight (ton), and
P = number of days with at least 0.01 inch of precipitation per year.

The particle size multiplier, k, was based on the EPA multipliers of 4.9 and 1.5 in developing the PM(TSP) and PM_{10} emission estimates, respectively. The particle size exponents, a and b, were based on the EPA multipliers. For exponent a, the exponents were 0.7 and 0.9 in developing the PM(TSP) and PM_{10} emission estimates, respectively. For b, the exponent was 0.45. The coal silt content was assumed to be 2.2 percent and the silt content for limestone and gypsum was 1.6 percent based on AP-42.

The PM(TSP) and PM_{10} emission factors for vehicle transportation on paved roads was derived from Section 13.2.1 in AP-42, are:

$$E = (k \ (s/12)^{a} (W/3)^{b} - C) \ (p/4 \times 365)](\text{lb/vehicle mile traveled})$$

where: E = emission factor (lb/vehicle mile traveled);,
k = particle size multiplier,
a,b = particle size exponents,
s = silt loading (g/m^2),
W = mean vehicle weight (ton),
C = exhaust, brake and tire correction factor (0.00047),
p = number of days with at least 0.01 inch of precipitation per year (113 inches).

The particle size multiplier, k, was based on the EPA multipliers of 0.082 and 0.016 in developing the PM(TSP) and PM_{10} emission estimates, respectively. The particle size exponents, a and b, were based on the EPA multipliers. For exponent a and b, the exponents were 0.65 and 1.5, respectively, for the PM(TSP) and PM_{10} emission estimates. The silt loading was assumed to be 1 g/m^2 based on AP-42. The vehicle weights were 32.5 tons loaded and 12.5 tons empty.

Control efficiencies were based on EPA's fugitive dust background document (EPA, 1992), AP-42, and information about the source and historical fugitive emission factors. Appendix A contains the basis of the control efficiencies.

For dust collection systems with fabric filters, an emission rate of 0.01 grain per standard cubic foot (g/scf) was used. This is a typical guarantee for fabric filters. Annual and maximum daily emissions for these sources were based on their operation (i.e., loading rates and coal usage).

Table 2-5 presents a summary of emissions from material handling operations. The material handling was based on using a conservative basis for estimating emissions. FGPP was assumed to operate at a 100-percent capacity factor (8,760 hours per year at 100-percent load for both boilers). The amounts of fuel, limestone, bottom ash, fly ash, and FGD byproducts were the maximum amounts for the fuels being considered for FGPP. All by-products were assumed to be transported offsite by truck to maximize emissions from paved roads. Appendix A presents detailed emissions on emissions from each air emission point and the basis of the emissions calculations.

An auxiliary boiler rated at 200,000 lb/hr will be installed to supply steam during startup. The auxiliary boilers will fire 0.0015-percent distillate oil. Table 2-6 presents performance and emissions information of the auxiliary boilers firing distillate oil. Annual emissions for each boiler are based on a capacity factor of 10 percent or equivalent to operating 876 hours/year at maximum capacity.

Each unit will be equipped with 100-percent capability, 2,000-kilowatt (kW) emergency generators. These emergency generators will be used when electric power cannot be transmitted into the FPL transmission system and is unavailable to the Site. This primarily would occur during catastrophic events such as hurricanes. At a maximum expected operation of 160 hours per year, the emissions of any regulated air pollutant will not exceed 5 TPY. At this emission rate, each emergency generator is an exempt emission unit and can be considered an insignificant activity for air permitting purposes.

FGPP will have a distillate oil-fired fire pump that is rated at 500 hp.

Table 2-7 contains emissions and manufacturer's information for the emergency generators and fire pump. Typically, these emergency generators would be operated 1 to 2 hours per month for maintenance and reliability testing or approximately 12 to 24 hours per year.

Note that the estimated annual emissions provided a worst-case estimate for determining PSD applicability and are not representative of normal annual operation.

A summary of the maximum total potential annual emissions estimated for FGPP is presented in Table 2-8.

FGPP will have various emission activities that would be classified under Rule 62-210.300(3), F.A.C., as insignificant emission activities by meeting the criteria for either categorical or generic exemptions. These emission activities include steam vents, lube oil systems and tanks, laboratory equipment, fire and safety equipment, brazing, soldering and welding equipment, distillate oil tanks, vacuum pumps used in laboratory operations, internal combustion engines (vehicles), and other ancillary equipment that emit insignificant amounts of air emissions. These emission activities contribute negligible amounts of air pollutants and do not have any effect on the regulatory applicability of FGPP. These insignificant emission activities will be identified in the Title V application as required in Rule 62-213.420(3)(n).

2.4 STRUCTURES AND STACK SAMPLING FACILITIES

The dimensions of the buildings and structures used to analyze the Good Engineering Practice (GEP) stack height are presented in Section 6.0. Stack sampling facilities will be constructed in accordance to Rule 62-297.310(6) F.A.C.

2.5 EXCESS EMISSIONS

Emissions during startup of the units will be minimized by the use of the auxiliary boilers to provide steam for cleaning the boiler and steam generator and the use natural gas or 0.0015-percent sulfur distillate oil igniters in the boilers to warm the boiler and steam turbine. The startup of the units will require an excess emission allowance greater than 2 hours allowed under the FDEP rules for certain air emissions. There are three types of possible startup conditions that are summarized in Figure 2-10 and discussed below.

- Cold Start: A cold start is defined as a startup after the boiler has been shut down for more than 48 hours. The auxiliary boilers are started and operated for about 80 hours to warm and clean the steam generator. The WESP and wet FGD system are started prior to the ignitors. The steam turbine is then ramped up using steam generated from the boiler firing the startup fuels to about 30-percent load. The auxiliary boiler is shutdown once sufficient steam is provided by the boiler to the steam turbine. Total auxiliary boiler operation during a cold start is up to 80 hours. The ignitors are fired for about 14 hours to reach 30-percent load. After stabilizing at 30-percent load and pulverizers brought into service. The SCR system can be started when the SCR inlet reaches 600°F. The units would be in compliance. The total duration is about 24 hours with the ignitors used for about 14 hours.
- Warm Start: A warm start is defined as a startup after the boiler has been shut down for more than 8 hours, but not more than 48 hours. The startup procedure is similar to a cold start except the durations are shorter. The auxiliary boiler is initially operated for about 44 hours. The ramp-up to 30-percent load using ignitors takes about 9 hours. The total duration of the startup cycle is about 14 hours.
- Hot Start: A hot start is defined as a startup after the boiler has been shut down (unfired) for 8 hours or less. The hot start procedure is similar to a warm start. The auxiliary boiler is initially operated for about 12 hours. The ramp-up using ignitors to 30-percent load takes about 1.5 hours. The total duration of the startup cycle is about 6 hours.

The emissions from the auxiliary boilers during startup will comply with the emission rates proposed for the Project. The use of 0.0015 percent sulfur distillate fuel, along with the operation of the fabric filter, WESP and wet FGD systems will minimize emissions of those pollutants associated with contaminants in the fuel (PM, SO_2 and SAM). Because the ignitors and the boiler will be operating at low load conditions and the SCR will not be operating, excess emissions for combustion products, such as CO, VOC and NO_x, may occur. An allowance for excess emissions during startup is requested according to the times required to fire the ignitors and reach a load where the SCR is turned on. The maximum estimated times for each type of startup is 24 hours for a cold start, 14 hours for a warm start and 6 hours for a hot start.

Because the ignitors and the boiler will be operating at low load conditions and the SCR will not be operating, excess emissions for combustion products, such as CO, VOC, and NO_x, may occur. However, the potential emissions for these pollutants will not be greater than the mass emissions provided in Table 2-2. Mass emissions during startup will remain low due to the operation at low loads during the startup process.

TABLE 2-1
ULTIMATE AND PROXIMATE ANALYSIS OF REPRESENTATIVE FUELS AND FUEL BLENDS, FGPP

		Central Appalachian			Typical Imported Coals				
	UNITS	Minimum	Average	Maximum	Minimum	Average	Maximum	Petroleum Coke	Central Appalachian, Imported and Petroleum Coke
Ultimate Analysis									
Carbon	%	64.57	70.73	76.74	62.20	64.40	65.80	79.00	69.85
Sulfur	%	0.61	0.91	1.28	0.50	0.67	0.80	6.75	1.98
Oxygen	%	4.50	5.65	6.03	6.34	7.73	10.14	0.78	5.51
Hydrogen	%	4.15	4.62	5.35	4.25	4.60	4.95	3.30	4.35
Nitrogen	%	1.15	1.46	1.66	1.00	1.17	1.36	1.60	1.37
Chlorine	%	0.04	0.13	0.29	0.01	0.03	0.06	0.02	0.07
Ash	%	6.26	10.05	15.25	7.90	8.90	11.80	0.50	7.68
Moisture	%	5.50	6.45	7.50	10.40	12.50	13.20	8.00	9.18
Proximate Analysis									
Moisture	%	5.50	6.45	7.50	10.40	12.50	13.20	8.00	9.18
Volatile matter	%	30.75	31.22	36.07	32.00	33.00	33.90	10.00	27.69
Fixed Carbon	%	46.89	52.28	53.94	43.80	45.60	47.80	81.50	55.45
Ash	%	6.26	10.05	15.25	7.90	8.90	11.80	0.50	7.68
Gross (Higher) Heating Value	Btu/lb	11,564	12,510	13,090	11,100	11,300	11,399	13,676	12,324
Hardgrove Grindability	HGI	42.00	44	60	47	50	53	35	45

Note: Petroleum Coke will be co-fired with coal at a maximum amount of 20 percent on a weight basis.

Source: FPL, 2006.

TABLE 2-2

TYPICAL DISTILLATE OIL COMPOSITION

Elements	Maximum
Carbon Residue	0.35 % on 10% Bottoms
Water and Sediment	0.05 %
Ash	0.01 %
Vanadium	0.5 ppm
Sodium and potassium	0.5 ppm
Lead	1 ppm
Calcium	2 ppm
Sulfur	0.0015 wt. %

High Heating Value (HHV) - 19,300 Btu/lb; 135,100 Btu/gallon.

Note: ppm = parts per million.

TABLE 2-3
AIR POLLUTANT EMISSIONS FOR CRITERIA POLLUTANTS FROM FGPP

		Data for Each Nominal 980 MW net Unit [a]			
Parameter	**Units**	**100% Load**	**70% Load**	**40% Load**	**Two Units**
Performance					
Net Power Output	kW	980,000	678,201	362,511	1,960,000
Heat Input (HHV)	MMBtu/hr	8,700	6,090	3,480	17,400
Capacity Factor		100%	100%	100%	100%
Stack Data					
Height	feet	500	500	500	
Diameter	feet	30	30	30	
Temperature	°F	135	135	135	
Velocity	ft/sec	55	37	21	
Emissions					
SO_2	lb/MMBtu	0.04	0.04	0.04	
	lb/hr	348	244	139	696
	tons/year	1,524	1,067	610	3,048
Filterable PM/PM_{10}	lb/MMBtu	0.013	0.013	0.013	
	lb/hr	113	79	45	226
	tons/year	495	347	198	991
NO_x	lb/MMBtu	0.05	0.05	0.05	
	lb/hr	435	305	174	870
	tons/year	1,905	1,334	762	3,811
CO	lb/MMBtu	0.150	0.150	0.150	
	lb/hr	1,305	914	522	2,610
	tons/year	5,716	4,001	2,286	11,432
VOC	lb/MMBtu	0.0034	0.0034	0.0034	
	lb/hr	29.6	20.7	11.8	59
	tons/year	129.6	90.7	51.8	259
Sulfuric Acid Mist	lb/MMBtu	0.004	0.004	0.004	
	lb/hr	34.8	24.4	13.9	70
	tons/year	152	107	61	305

[a] Based on maximum fuel input for representative fuels and fuel blends shown on Table 2-1.

Sources: FPL 2006; Worley-Parsons, 2006; Golder, 2006.

TABLE 2-4

PHYSICAL, PERFORMANCE, AND EMISSIONS DATA FOR ONE MECHANICAL DRAFT COOLING TOWER

Parameter	
Physical Data	
Number of Cells	32
Deck Dimensions, ft	
	864
Width	108
Height	50
Stack Dimensions	
Height, ft	60
Stack Top Effective Inner Diameter, per cell, ft	35.0
Effective Diameter, all cells, ft	198.0
Performance Data	
Discharge Velocity, ft/min	1,395
Circulating Water Flow Rate (CWFR), gal/min	460,855
Design hot water temperature, °F	98.29
Design cold water temperature, °F	78.37
Heat Rejected, million Btu/hr	4,044
Design Air Flow Rate per cell, acfm	1,342,235
Liquid/ Gas (Air Flow) (L/G) Ratio	1.203
Hours of operation	8,760
Emission Data	
Drift Rate[a] (DR), percent	0.0005
Total Dissolved Solids (TDS) Concentration [b], maximum ppm	25,000
Solution Drift [c] (SD), lb/hr	1,153
PM Drift [d], lb/hr	28.83
tons/year	126.26
PM_{10} Drift [e]	
PM_{10} Emissions, lb/hr	1.77
tons/year	7.7

[a] Drift rate is the percent of circulating water.

[b] A TDS of 5,000 results in maximum PM emissions.

[c] Includes water and based on circulating water flow rate and drift rate (CWFR x DR x 8.34 lb/gal x 60 min/hr).

[d] PM calculated based on total dissolved solids and solution drift (TDS x SD).

[e] PM_{10} based on "Calculating Realistic PM_{10} Emissions from Cooling Towers," Reisman Frisbre, 2001 (see Appendix A).

Sources: GEA, 2006; FPL, 2006; Golder, 2006.

TABLE 2-5

SUMMARY OF PM EMISSIONS FROM THE MATERIAL HANDLING OPERATIONS AT FGPP

	Emission Rate (lb/hr)		Emission Rate (TPY)	
Operation	PM 24-hour Rate	PM10 24-hour Rate	PM Annual Rate	PM10 Annual Rate
Coal Handling System				
Emission Points	0.98	0.98	4.30	3.82
Transfer Points (Fugitive)	0.44	0.21	1.30	0.61
Fugitive Emissions	1.78	0.54	3.06	0.88
Limestone Handling System- Dust Collection and Ventilation				
Emission Points	0.04	0.04	0.20	0.15
Transfer Points (Fugitive)	0.25	0.12	1.98	0.94
Fugitive Emissions	0.57	0.13	1.01	0.22
Fly Ash Handling System				
Emission Points	0.26	0.26	1.13	1.13
Transfer Points (Fugitive)	0.051	0.024	0.121	0.057
Bottom Ash Handling System				
Transfer Points (Fugitive)	0.0318	0.0150	0.0760	0.0359
Fugitive Emissions	0.14	0.03	0.42	0.09
Gypsum Handling System				
Transfer Points (Fugitive)	0.114	0.054	0.912	0.431
Fugitive Emissions	0.004	0.001	0.006	0.002
Byproduct Handling System				
Fugitive Emissions	5.64	1.21	20.18	4.10
Reagent Handling System				
Emission Points	0.03	0.03	0.13	0.13
TOTAL EMISSIONS	10.34	3.64	34.80	12.60
Number of Sources	53			

TABLE 2-6
PERFORMANCE, STACK PARAMETERS, AND EMISSIONS FOR THE START-UP STEAM BOILER ASSOCIATED WITH FGPP - DISTILLATE OIL FIRING

	Boiler-100% Load	**Boiler-75% Load**	**Boiler-50% Load**
Performance			
Fuel	No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil
Heat Content (HHV-Btu/lb)	19,300	19,300	19,300
Fuel Density (lb/gal)	7.0	7.0	7.0
Fuel Usage (gallons/hr-diesel)	1,666.39	1,245.44	829.02
Rating (lb steam/hr-boiler)[a]	200,000	150,000	100,000
Heat Input (mmBtu/hr-HHV)[a]	225.13	168.26	112.00
Maximum Hours per Year	876	876	876
Maximum Fuel Usage (gallons/yr)	1,459,758	1,091,005	726,218
Exhaust Flow[a]			
Mass Flow (lb/hr)	205,035	160,906	107,096
Molecular Weight	28.74	28.74	28.74
Moisture (%)	12.29	12.29	12.29
Stack Parameters			
Diameter (ft)	5.00	5.00	5.00
Height (ft)	330.00	330.00	330.00
Temperature (°F)	298.00	280.00	265.00
Velocity (ft/sec)	56	43	28
Flow (acfm)	65,792	50,406	32,869
Emissions			
SO_2 -Basis (%S) [b]	0.0015%	0.0015%	0.0015%
(lb/hr)	0.350	0.262	0.174
(tpy)	0.153	0.115	0.076
NO_x - (lb/MMBtu) [a]	0.120	0.120	0.120
(lb/hr)	27.016	20.191	13.440
(tpy)	11.833	8.844	5.887
CO - (lb/MMBtu) [a]	0.077	0.077	0.077
(lb/hr)	17.335	12.956	8.624
(tpy)	7.593	5.675	3.777
VOC - (lb/mmBtu) [c]	0.005	0.005	0.005
(lb/hr)	1.126	0.841	0.560
(tpy)	0.493	0.368	0.245
PM/PM_{10} - (lb/mmBtu) [c]	0.030	0.030	0.030
(lb/hr)	6.754	5.048	3.360
(tpy)	2.9582	2.2109	1.4717

[a] FPL, (2006), Nebraska Boiler (2005); Golder Associates Inc., (2006)

[b] Typical maximum sulfur content for distillate fuel oil

[c] Emissions based on EPA, 1998 (AP-42, Tables 1.3-1 and 1.3-3).

TABLE 2-7
PERFORMANCE AND EMISSION DATA FOR THE EMERGENCY GENERATORS AND EMERGENCY FIRE PUMP ASSOCIATED WITH THE FGPP

Parameter	**Emergency Generator**	**Emergency Fire Pump**
Performance		
Number of Units	2	1
Rating (kW)	2,000	403
Rating (hp)	2,680	540
Fuel	Diesel	Diesel
Fuel Heat content (Btu/lb) (HHV)	19,300	19,300
Fuel density (lb/gal)	7.0	7.0
Heat input (MMBtu/hr) (HHV)	18.77	3.90
Fuel usage (gallons/hr)	138.9	28.9
Maximum operation (hours)	160	40
Maximum fuel usage (gallons/yr)	22,224	1,156
Emissions		
SO_2 - Basis (%S)	0.0015%	0.0015%
Conversion of S to SO_2	100	100
Molecular weight SO_2/ S (64/32)	2	2
Emission rate (lb/hr)	0.029	0.006
(tpy)	0.0023	0.0001
(tpy/plant)	0.005	0.000
NO_x - Basis (g/hp-hr) [1]	4.8	4.8
Emission rate (lb/hr)	28.4	5.7
(tpy)	2.27	0.11
(tpy/plant)	4.538	0.114
CO - Basis (g/hp-hr) [1]	2.6	2.6
Emission rate (lb/hr)	15.4	3.1
(tpy)	1.23	0.06
(tpy/plant)	2.458	0.062
VOC - Basis (g/hp-hr) [1]	0.5	0.5
Emission rate (lb/hr)	3.0	0.6
(tpy)	0.24	0.01
(tpy/plant)	0.473	0.012
PM/PM_{10} - Basis (g/hp-hr) [1]	0.15	0.15
Emission rate (lb/hr)	0.9	0.2
(tpy)	0.07	0.00
(tpy/plant)	0.142	0.004

Note: Performance and emissions shown for each unit.

[1] Emissions for emergency generator based on EPA Tier 2 Standards for generator sets >900 kW (71 FR 9154; Table 1 of Section II); Emissions for fire pump engine based on Tier 3 Standards for engines equal to or greater than 300 hp (71 FR 9154; Table 4 to Subpart IIII of Part 60); VOCs for both engines based on EPA Tier 1 reduced by 50%.

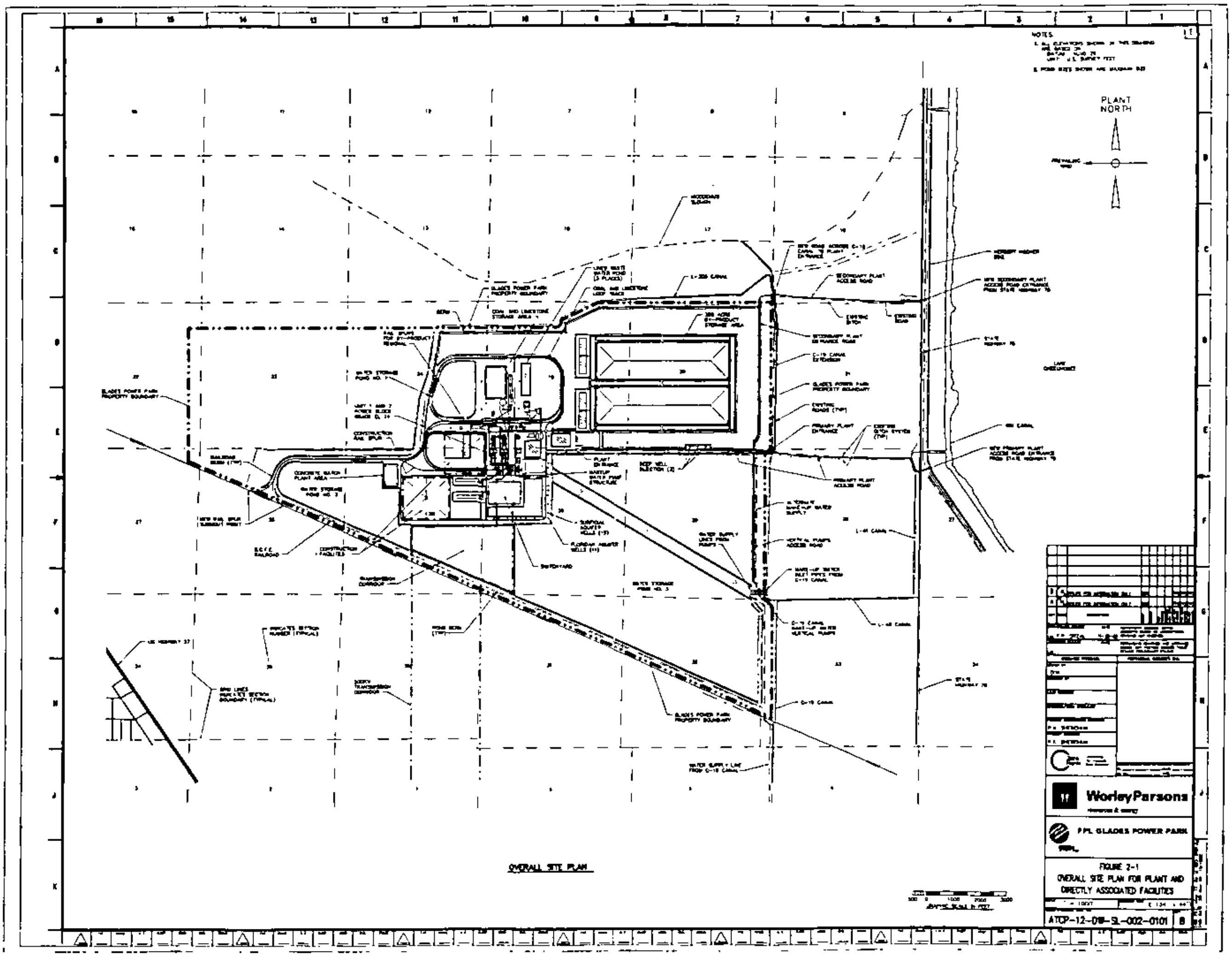
Source: Caterpillar, Golder; 2006.

TABLE 2-8

SUMMARY OF POTENTIAL AIR EMISSIONS (TPY) FOR FGPP BASED ON 100-PERCENT CAPACITY FACTOR

Pollutant	Two 980-MW (net) Units	Two Cooling Towers	Material Handling	One Startup Auxiliary Boiler	Two Emergency Diesel Engines and Fire Pump	Total Emissions	PSD Significant Emission Rate (tons/year)	PSD Review Required?
SO_2	3,048			0.15	0.005	3,049	40	Yes
PM	991	252.52	34.80	2.96	0.15	1,281	25	Yes
PM_{10}	991	15.49	12.60	2.96	0.15	1,022	15	Yes
NO_x	3,811			11.83	4.65	3,827	40	Yes
CO	11,432			7.59	2.52	11,442	100	Yes
VOC (as methane)	259			0.49	0.48	260	40	Yes
Sulfuric Acid Mist	305			Neg	Neg	305	7	Yes
Fluoride	17.5			Neg	Neg	18	3	Yes
Lead	0.2			Neg	Neg	0.2	0.6	No
Mercury	0.09			Neg	Neg	0.09	0.1	No

Note: Neg = negligible.


NOTES
PLANT NORTH
LAKE OKEECHOBEE
HERBERT HOOVER DIKE
NEW SECONDARY PLANT ACCESS ROAD ENTRANCE FROM STATE HIGHWAY 78
STATE HIGHWAY 78
NEW PRIMARY PLANT ACCESS ROAD ENTRANCE FROM STATE HIGHWAY 78
SECONDARY PLANT ACCESS ROAD
EXISTING DITCH
EXISTING ROAD
SECONDARY PLANT ENTRANCE ROAD
C-19 CANAL EXTENSION
GLADES POWER PARK PROPERTY BOUNDARY
EXISTING ROADS (TYP)
PRIMARY PLANT ENTRANCE
EXISTING DITCH SYSTEM (TYP)
PRIMARY PLANT ACCESS ROAD
L-41 CANAL
MAKE-UP WATER INLET PIPES FROM C-19 CANAL
C-19 CANAL
OVERALL SITE PLAN
WorleyParsons
FPL GLADES POWER PARK
FIGURE 2-1
OVERALL SITE PLAN FOR PLANT AND DIRECTLY ASSOCIATED FACILITIES
ATCP-12-DW-SL-002-0101
B

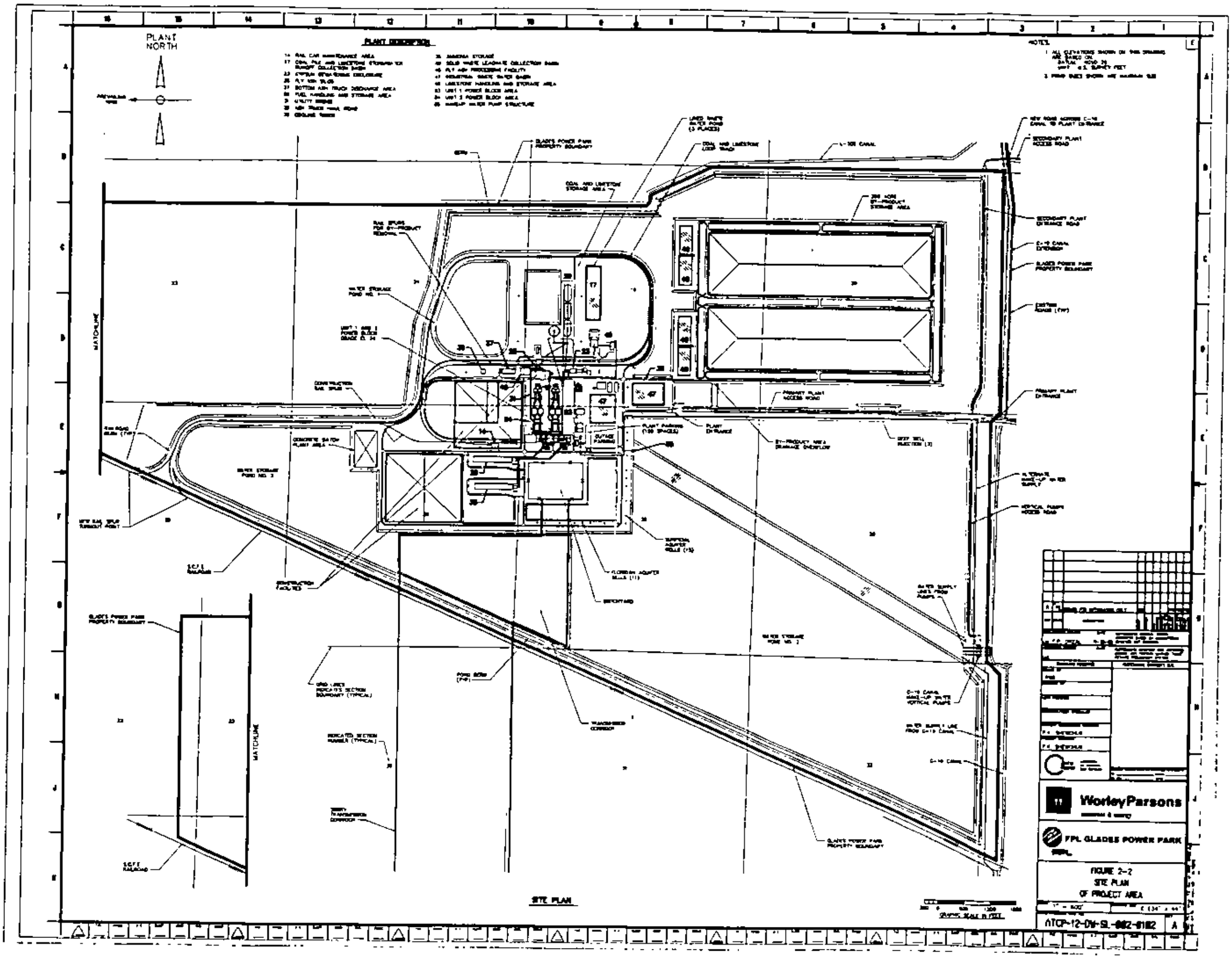


FIGURE 2-2
SITE PLAN
OF PROJECT AREA

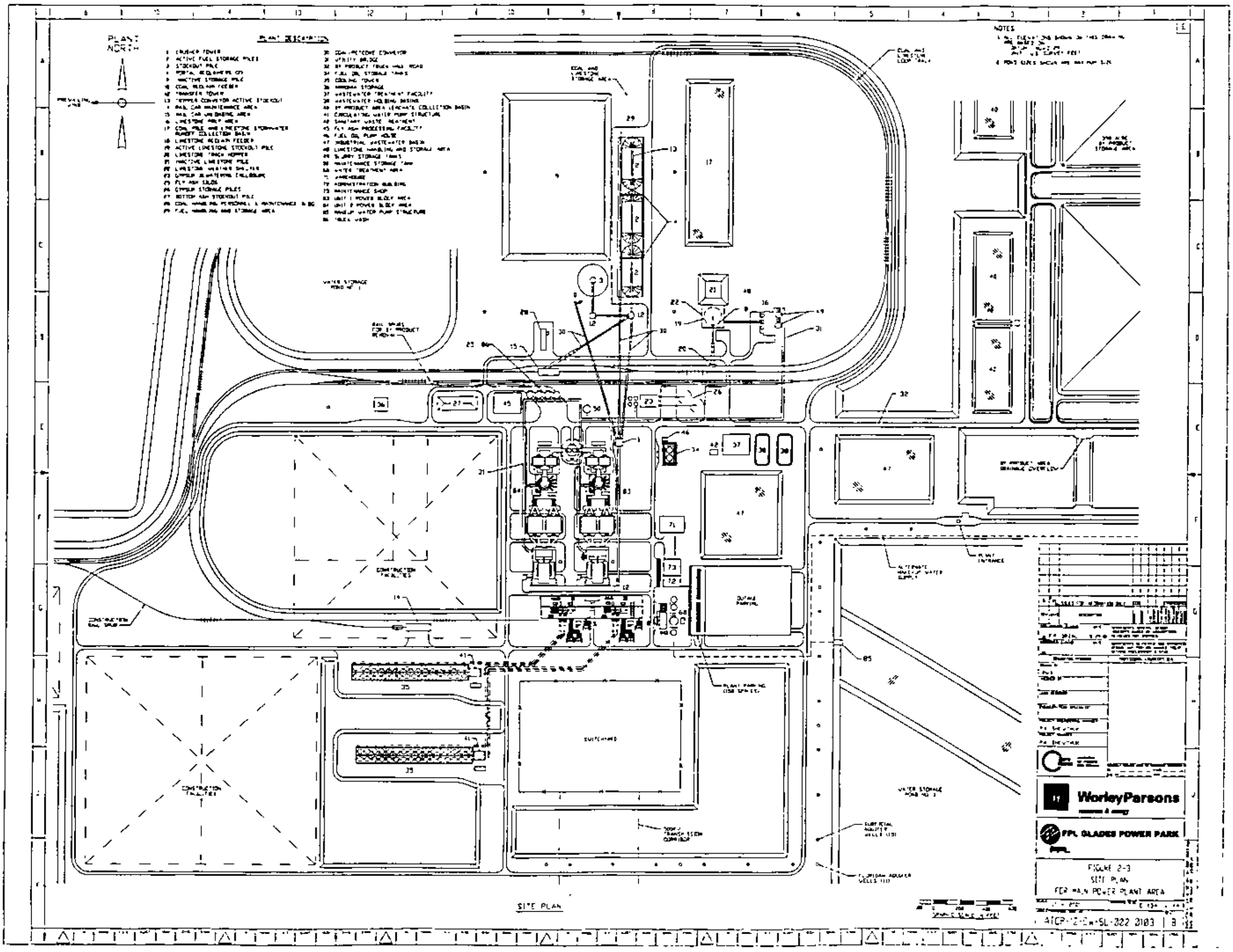


FIGURE 2-3
SITE PLAN
FOR MAIN POWER PLANT AREA

ATCP-12-C -SL-322 0103 | B

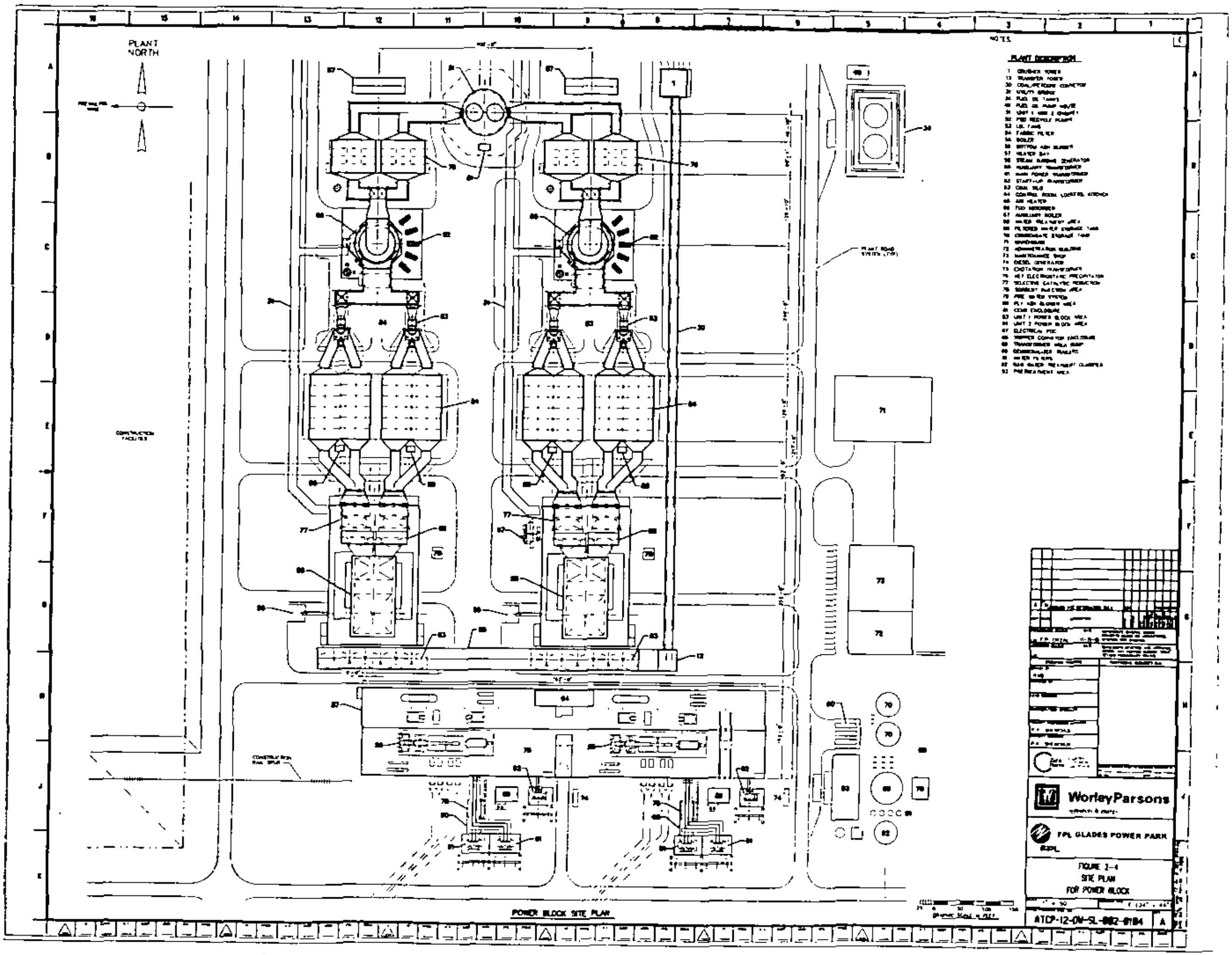
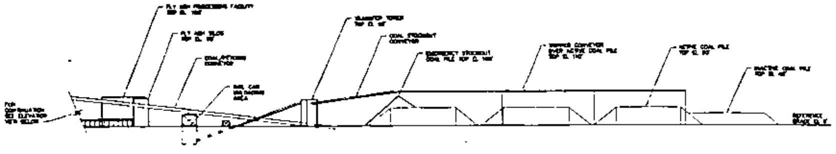
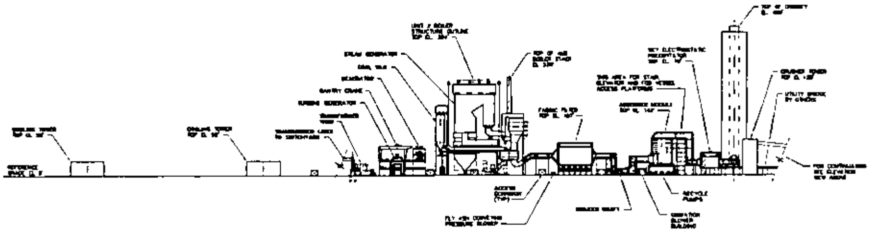


FIGURE 2-4
SITE PLAN
FOR POWER BLOCK

NOTES:



ELEVATION VIEW LOOKING WEST



ELEVATION VIEW LOOKING WEST

WorleyParsons

FPL GLADES POWER PARK

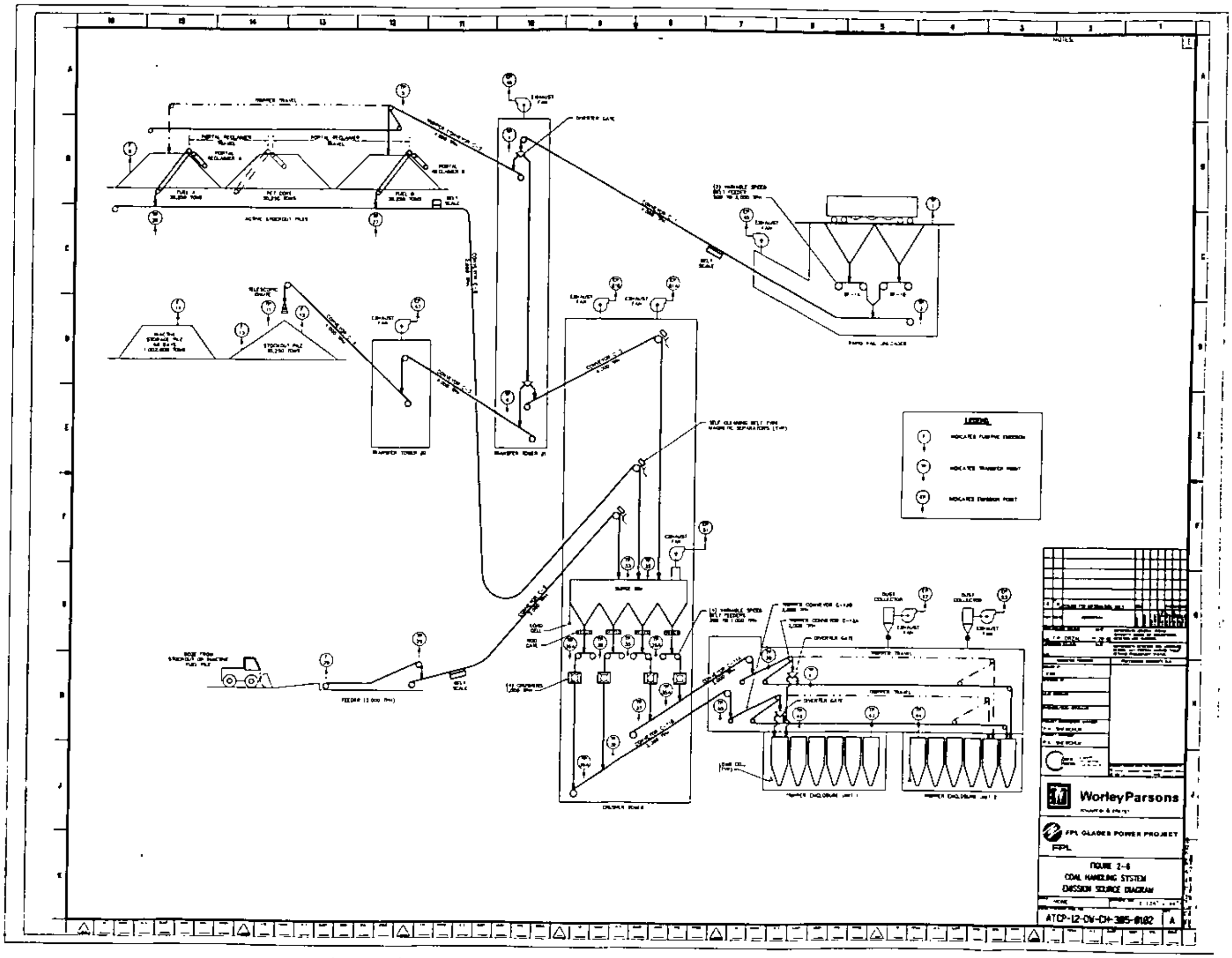
FPL

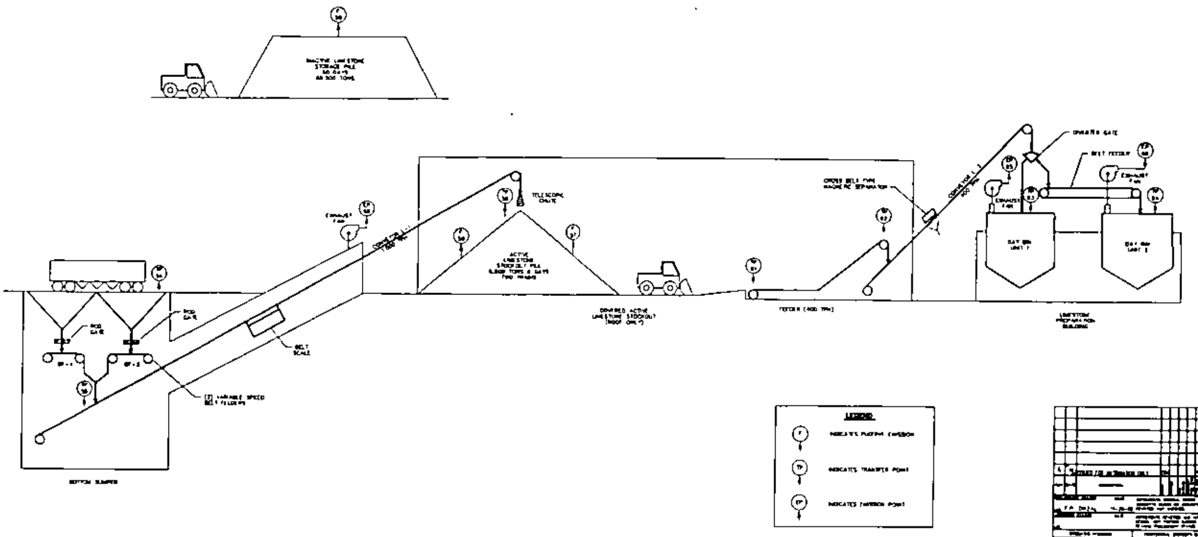
FIGURE 3-6

FGPP PROFILE

1" = 100'

A


WorleyParsons
FPL GLADES POWER PROJECT
FPL
FIGURE 2-6
COAL HANDLING SYSTEM
EMISSION SOURCE DIAGRAM
ATCP-12-DW-CH-305-0102
A



WorleyParsons

FPL GLADES POWER PARK

FPL

FIGURE 2-7
LIMESTONE HANDLING SYSTEM
EMISSION SOURCE DIAGRAM

ATCP-12-DW-LH-305-0102 A

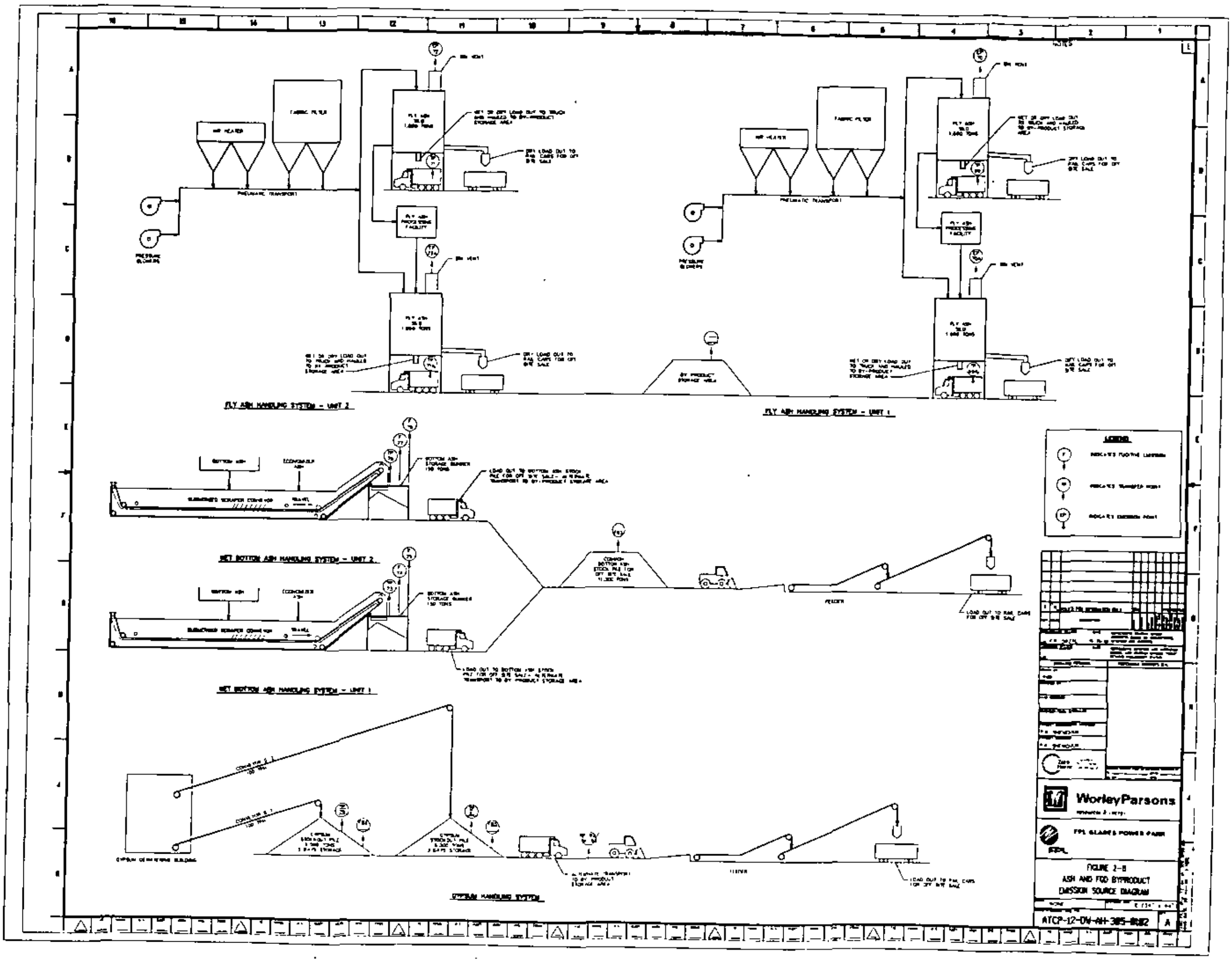
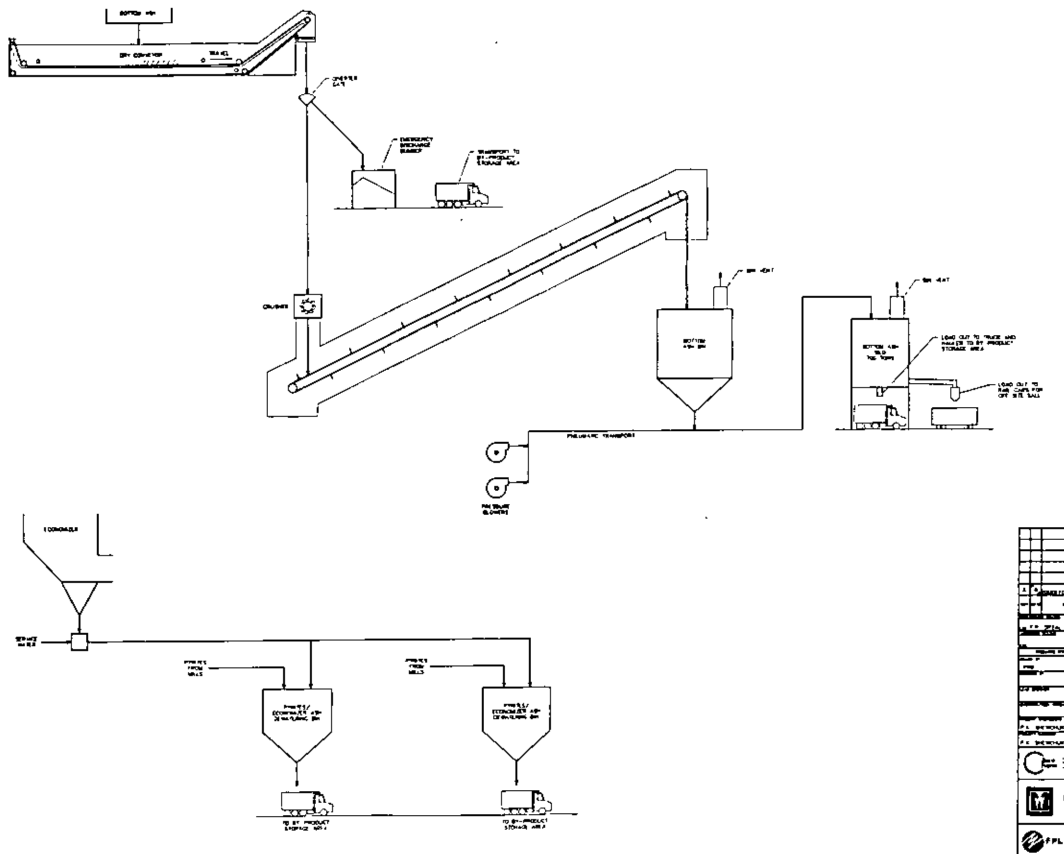


FIGURE 2-8
ASH AND FGD BYPRODUCT
EMISSION SOURCE DIAGRAM

ATCP-12-DW-AH-305-0002 A



ALTERNATE DRY BOTTOM ASH HANDLING SYSTEM - UNIT 1.

WorleyParsons

FPL GLADES POWER PARK

FPL

FIGURE 2-9
CONCEPTUAL FLOW DIAGRAM OF DRY
BOTTOM ASH HANDLING SYSTEM

NONE

ATCP-12-DV-AH-385-0003 A

FIGURE 2-10

ESTIMATED STARTUP TIMES - FPL GLADES POWER PARK

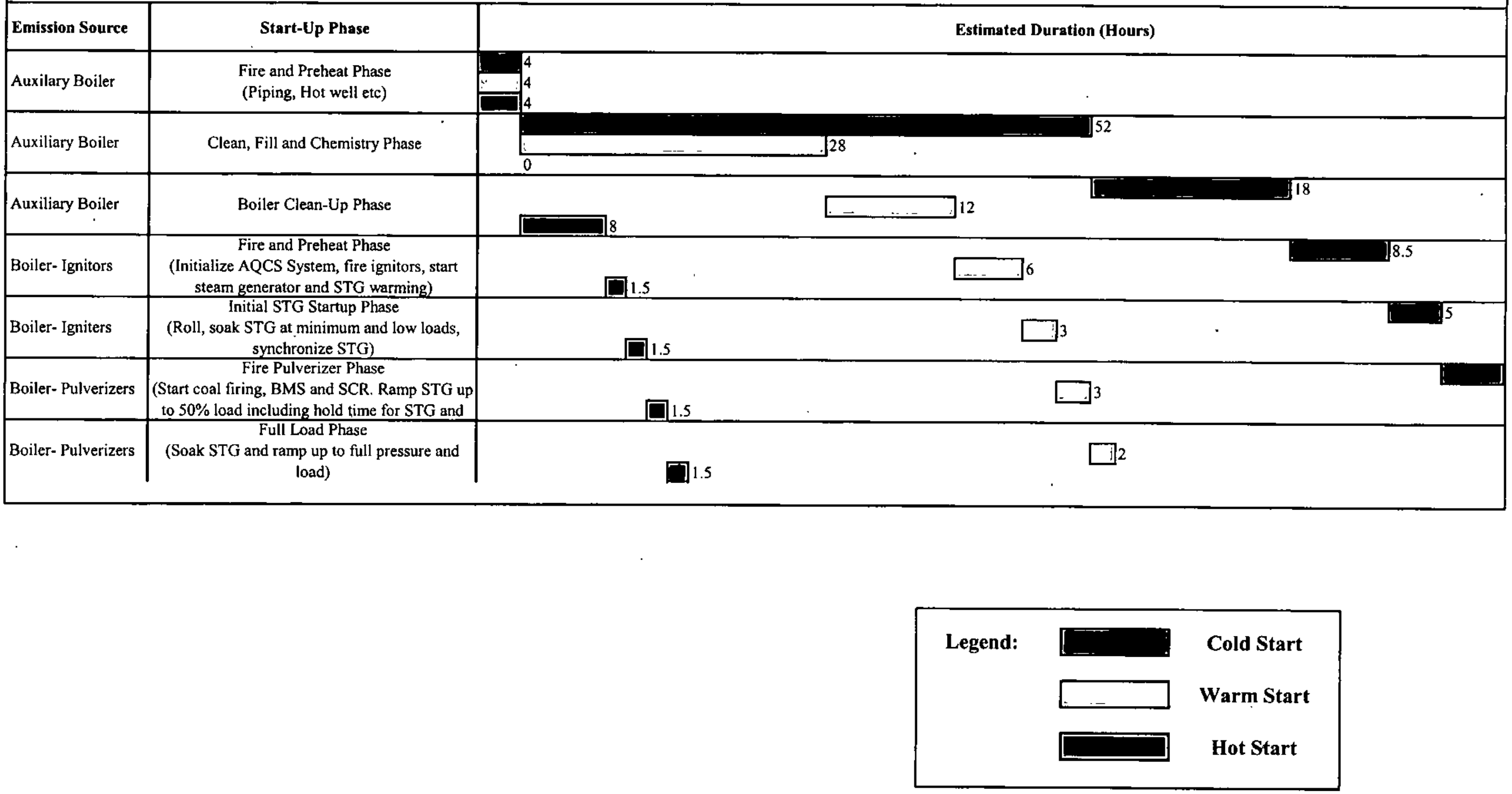


Figure 2-10
Estimated Startup Times
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2005.

Golder Associates

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to FGPP. These regulations must be satisfied before the facility can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and State of Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas; and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a pre-construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA; therefore, PSD approval authority has been granted to FDEP.

A "major facility" is defined as any 1 of 28 named source categories that have the potential to emit 100 TPY or more or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. PSD review would apply for each pollutant at a major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

Regulations have been promulgated providing certain increases above an air quality baseline concentration level of SO_2, PM_{10}, and NO_2 that would constitute significant deterioration. The EPA class designations and allowable PSD increments are presented in Table 3-1. The State of Florida has adopted the EPA class designations and allowable PSD increments for SO_2, PM_{10}, and NO_2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 51.166, *Prevention of*

Significant Deterioration of Air Quality. The State of Florida's PSD regulations are found in Rule 62-212.400, F.A.C. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to good engineering practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that BACT be applied to control emissions from the source (Rule 62-212.400, F.A.C.). The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

"Best Available Control Technology" or "BACT" is defined in Rule 62-210.200(38), F.A.C., as:

> (a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:
>
> 1. Energy, environmental and economic impacts, and other costs;
> 2. All scientific, engineering, and technical material and other information available to the Department; and
> 3. The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

> (b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.
>
> (c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.
>
> (d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in *Guidelines for Determining Best Available Control Technology (BACT)* (EPA, 1978), in the *PSD Workshop Manual-Draft* (EPA, 1980) and in the *New Source Review Workshop Manual-Draft* (1990). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. Under these guidelines, BACT must be conducted on a case-by-case basis. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the facility. BACT must, as a minimum, demonstrate compliance with any applicable new source performance standards (NSPS; 40 CFR Part 60) and any applicable National Emission Standard for Hazardous Air Pollutants (NESHAPs; 40 CFR 61 and 63). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

EPA has issued a draft guidance document on the top-down approach entitled, *Top-Down Best Available Control Technology Guidance Document* (EPA, 1990). EPA's BACT guidelines include a "top-down" approach to determine the "best available control technology" for application at a particular facility. These guidelines discuss the BACT as a "case by case" analyses to identify the most stringent emission control technologies that have been applied to the same or similar source categories, and then to select a BACT emission rate, taking into account technical feasibility and energy, environmental and economic impacts specific to the project. The most effective control effective control alternative not rejected from the analysis is proposed as BACT.

EPA's BACT guidelines establish a specific five-step analytical process for conducting a BACT determination. The five steps consist of: 1) identifying the potentially applicable control technologies for the proposed process or source, 2) evaluating the technical options for feasibility taking into consideration source specific factors, 3) comparing the remaining control technologies based on effectiveness, 4) evaluating the remaining options taking into consideration energy, environmental and economic impacts, and 5) selecting BACT based on the above analyses.

3.2.3 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication *Guideline on Air Quality Models (Revised).* The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is above significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. The levels are as follows:

Pollutant	Averaging Time	Proposed EPA PSD Class I Significant Impact Levels ($\mu g/m^3$)
SO_2	3-hour	1
	24-hour	0.2
	Annual	0.1
PM_{10}	24-hour	0.3
	Annual	0.2
NO_2	Annual	0.1

Note: $\mu g/m^3$ = micrograms per cubic meter.

Although these levels have not been officially promulgated as part of the PSD review process and may not be binding for states in performing PSD reviews, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. The EPA action to incorporate Class I significant impact levels in the PSD process is part of implementing NSR provisions of the 1990 CAA Amendments. Because the process of developing the regulations will be lengthy, EPA believes that the proposed rules concerning the significant impact levels is appropriate to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels. Source impact analyses for PSD Class I Areas are performed if the source is within 200 kilometers (km) of the Class I Area.

Various lengths of meteorological data records can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If fewer than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and, therefore, will affect PSD increment consumption.

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations and after February 8, 1988, for NO_2 concentrations; and
2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP) and February 8, 1988, in the case of NO_2;
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application; and
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP) and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Rules 62-204.200(22); 204.360, F.A.C.). The minor source baseline for NO_2

has been set as March 28, 1988 (Rule 62-204.200(22); 204.360, F.A.C). It should be noted that references to PM(TSP) are also applicable to PM_{10}.

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the new major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. Data for a minimum of 4 months are required. Existing data from the vicinity of the proposed source may be used, if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that a new major stationary facility or major modification is exempt from the monitoring requirements with respect to a particular pollutant, if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the *de minimis* levels presented in Table 3-2 (Rule 62-212.400-3, F.A.C.). If a facility's predicted impacts are less than the *de minimis* levels, therefore, preconstruction monitoring will not be required pursuant to Rule 62-212.400(3)(e) F.A.C.

3.2.5 SOURCE INFORMATION/GEP STACK HEIGHT

Source information must be provided to adequately describe the proposed facility. The general type of information required for this facility is presented in Section 2.0.

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant cannot be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDEP (Rule 62-210.550, F.A.C.). GEP stack height is defined as the highest of:

1. 65 meters (m); or
2. A height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s); or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to 5 times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [Rule 62-212.400(5)(e), F.A.C.]. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (see Table 3-2).

3.2.7 AIR QUALITY-RELATED VALUES

An Air Quality Related Value (AQRV) analysis is required to assess the potential risk to AQRVs in PSD Class I areas. The Everglades National Park is the closest Class I area to FGPP and is located about 113 km south of the Site. The Chassahowitzka National Wilderness Area (NWA) is located about 239 km northwest of the Site and within the 200-km distance that requires a source impact analysis.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register, 1978).*

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Rule 62-212.500, F.A.C.), all major new facilities and modifications to existing major facilities, located in a nonattainment area, must undergo nonattainment review. Currently, there are no nonattainment areas in Florida.

3.4 EMISSION STANDARDS

3.4.1 NEW SOURCE PERFORMANCE STANDARDS

The NSPS are a set of national emission standards that apply to specific categories of new sources. As stated in the 1977 CAA Amendments, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

The ultra-supercritical boilers will be subject to emission limitations covered under 40 CFR Subpart Da, which limits NO_x, SO_2, and PM emissions from electric utility generating units capable of combusting more than 73 MW (250 MMBtu/hr) heat input using fossil fuel. EPA issued changes to these NSPS on February 27, 2006 (71 FR 9866). These NSPS, that are applicable to new affected facilities that commence construction after February 28, 2005, lowered the emission limits for PM, SO_2, and NO_x. The NSPS emission limit for PM is 0.14 pound per megawatt hour (lb/MW-hr) (gross energy) or 0.015 lb/MMBtu. As an alternative, PM is limited to 0.03 lb/MMBtu and 99.8-percent reduction from uncontrolled PM level when combustion solid fuel. SO_2 emissions are limited to 1.4 lb/MW-hr or 95-percent reduction, based on a 30-day rolling average. Subpart Da limits NO_x emissions to 1.0 lb/MW-hr (gross energy output) based on 30-day rolling average. Visible emissions are limited to 20-percent opacity (6-minute average) except up to 27-percent opacity is allowed for one 6-minute period per hour. FGPP will meet these emission limits.

EPA promulgated the Clean Air Mercury Rule (CAMR) that consisted of NSPS for new sources and a cap-and-trade program for new and existing sources. EPA's Hg emission limit for new sources was promulgated as part of 40 CFR 60, Subpart Da, and applies to new, modified, or reconstructed electric utility steam-generating units (40 CFR 60.45a; 70 FR 28653; May 18, 2005, and 71 FR 33388; June 9, 2006). The emission limit is production based and is 20.0×10^{-6} lb/MW-hr for bituminous coal. Mercury emission rates proposed for the FGPP will be well below these standards.

The auxiliary boilers are subject to the NSPS codified in 40 CFR Part 60, Subpart Db, Standards for Performance for Industrial-Commercial-Institutional Steam Generating Units, which is applicable to steam-generating units commencing construction after February 28, 2005, with a heat input capacity of greater than 100 MMBtu/hr. EPA issued changes to these NSPS on February 27, 2006 (71 FR 9866). When firing distillate oil, there are emission limits for SO_2, PM, and NO_x. For SO_2, using very low-sulfur oil, defined as fuel with a sulfur content of 0.3-percent sulfur or less would obviate the need to meet an SO_2 emission limit or percent reduction requirement. The PM emission limit is not required using very low sulfur oil. There is also a PM limit expressed as an opacity limit. The opacity limit is 20 percent as a 6-minute average, except for one 6-minute period not to exceed 27-percent opacity. A continuous opacity monitoring system is required when firing oil. The Subpart Db requirements limit the emissions of NO_x to 0.2 lb/MMBtu for high-heat-release rate units, and 0.1 lb/MMBtu for low-heat-release rate units. The boiler would be a high-heat-release rate unit since the heat release rate would be greater than 70,000 British thermal units per hour per cubic foot

(Btu/hr-ft^3). Based on the provisions in Sections 60.44b(j) and (k), the NO_x emissions would not apply to the auxiliary boilers because: (1) the capacity factor would be less 10 percent, (2) only natural gas and distillate oil is fired, (3) the capacity factor and fuel would be included in a federally enforceable permit and (4) the auxiliary boilers are less than 250 MMBtu/hr. Notwithstanding, the auxiliary boilers would meet a NO_x limit of 0.2 lb/MMBtu.

EPA promulgated final regulations establishing NSPS for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) (71 FR 39154; July 11, 2006). This regulation, promulgated as Subpart IIII of Part 60 establishes emission standards based on type, use, size, and year. This promulgation is part of other EPA regulations establishing emissions standards for stationary non-road engines.

The material handling operation associated with coal crushing and transfer are subject to the NSPS codified in 40 CFR Part 60 Subpart Y, Standards of Performance for Coal Preparation Plants. The activity of crushing coal, which will be performed by coal crushers prior to transfer and storage in the coal silos, is included in the definition of a "coal preparation plant". The emission limits for this NSPS is 20 percent opacity for coal processing and conveying equipment, and coal storage. The coal crushers and transfer equipment will be enclosed with vent filters in several locations to limit PM emissions. The PM emissions from these emission points will be less than the NSPS limits.

The grinding of limestone for use in the wet FGD system is subject to the NSPS codified in 40 CFR Part 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants. Limestone is defined as a nonmetallic mineral and the crushing or grinding of a nonmetallic mineral is an affected facility under the NSPS. The NSPS apply to certain activities with the most stringent requirements being a PM emission limit of 0.05 gram per dry standard cubic meter (gr/dscm) and 7-percent opacity. The emissions associated with limestone processing will meet these requirements.

In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring. These are summarized below:

40 CFR 60.7 - Notification and Record Keeping

(a)(1) Notification of the date of construction - 30 days after such date.

(a)(3) Notification of actual date of initial start-up - within 15 days after such date.

(a)(5) Notification of date that demonstrates continuous emission monitoring (CEM) - not less than 30 days prior to date.

60.7 (b) Maintain records of all start-ups, shutdowns, and malfunctions.

(c) Excess emissions reports – semi-annually by the 30th day following 6-month period (required even if no excess emissions occur).

(d) Maintain file of all measurements for 2 years.

60.8 - Performance Tests

(a) Must be performed within 60 days after achieving maximum production rate but no later than 180 days after initial start-up.

(d) Notification of Performance tests at least 30 days prior to them occurring.

3.4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

EPA promulgated the National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63, Subpart DDDDD. New or reconstructed large liquid fuel boilers must meet: 1) a PM emission rate of 0.03 lb/MMBtu, 2) a HCL emission rate of 0.0005 lb/MMBtu, and 3) a CO emission limit of 400 parts per million by volume on a dry (ppmvd) basis corrected to 3-percent oxygen based on a three-run average. Since the auxiliary boiler will have a capacity factor of 10 percent, it will be classified as in "limited use fuel subcategory". The emission limits apply to auxiliary boilers in this subcategory but monitoring requirements are not as extensive. The auxiliary boilers proposed for FGPP will meet these requirements. The emergency generators will be subject 40 CFR 63, Subpart ZZZZ, the Reciprocating Internal Combustion Engine (RICE) MACT Rule since they will be located at a major source of HAP emissions and will have a site rating of greater that 500 hp. The emergency generators will only be subject to the notification requirements of the RICE MACT.

3.4.3 FLORIDA RULES

The FDEP regulations for new stationary sources are covered in the F.A.C. The FDEP has adopted the EPA NSPS by reference in Rule 62-204.800(7). Therefore, FGPP is required to meet the same emissions, performance testing, monitoring, reporting, and record keeping requirements as those described in Subsection 3.4.1. FDEP has authority for implementing NSPS requirements in Florida.

3.4.4 FLORIDA AIR PERMITTING REQUIREMENTS

The FDEP regulations require any new source to obtain an air permit prior to construction. Major new sources must meet the appropriate PSD and nonattainment requirements as discussed previously. Required permits and approvals for air pollution sources include NSR for nonattainment areas, PSD, NSPS, NESHAPS, Permit to Construct, and Permit to Operate. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, 62-210.300(1), and Chapter 62-212.400, F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.5 LOCAL AIR REGULATIONS

Glades County has no specific ordinances or requirements related to air emissions or impacts from FGPP.

3.5 SOURCE APPLICABILITY

3.5.1 AREA CLASSIFICATION

The facility is located in Glades County, which has been designated by EPA and FDEP as an attainment area (includes unclassifiable) for all criteria pollutants. Glades County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_2. The nearest Class I area is the Everglades National Park (NP) located about 113 km (68 miles) to the south of the Site and within the 300-km distance requiring a PSD Class I air quality analysis.

3.5.2 PSD REVIEW

Pollutant Applicability

FGPP is considered to be a major facility because the emissions of several regulated pollutants are estimated to exceed 100 TPY and the emissions units are in one of the 28 listed categories. FGPP is a new major facility under the PSD rules, and PSD review is required for any pollutant for which the emissions exceed the PSD significant emission rates. As shown in Table 3-3, potential emissions from FGPP will trigger PSD for PM(TSP), PM_{10}, SO_2, NO_x, CO, VOC, SAM, and fluorides. Impacts for the pollutants that are predicted to be above the significant impact levels require a modeling analysis incorporating the impacts from other sources.

As part of the PSD review, a PSD Class I increment analysis is required if the proposed facility's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area is about 113 km (71 miles) from the Site, and a PSD Class I increment analysis and an evaluation of impacts to AQRVs is required.

Emission Standards

The applicable NSPS for the ultra-supercritical steam generators is 40 CFR Part 60, Subpart Da. The proposed emissions for FGPP will be below the specified limits (see Section 4.0).

Ambient Monitoring

Based on the estimated pollutant emissions from the Project (see Table 3-4), a pre-construction ambient monitoring analysis is required for PM_{10}, SO_2, NO_2, CO, and O_3 (based on VOC emissions). If the net increase in impact of PM_{10}, SO_2, NO_2, and CO is less than the applicable *de minimis* monitoring concentration (100 TPY in the case of VOC), then an exemption from the pre-construction ambient monitoring requirement is available by Rule 62-212.400(3)(e) F.A.C. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

As shown in Table 3-4, FGPP's impacts are predicted to be below the applicable *de minimis* monitoring concentrations for PM_{10}, SO_2, NO_2, and CO. Therefore, pre-construction monitoring is not required to be submitted for these pollutants. The emissions of VOC are above the *de minimis* monitoring threshold for O_3. The monitoring analysis for O_3 is presented in Section 5.0.

GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 meter (m) [(213 feet (ft)] high. The stack for FGPP will be 499 ft. This stack height does not exceed the GEP stack height of 512 ft.

3.5.3 NONATTAINMENT REVIEW

The facility Site is located in Glades County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment requirements are not applicable.

3.5.4 OTHER CLEAN AIR ACT REQUIREMENTS

The 1990 CAA Amendments established a program to reduce potential precursors of acidic deposition. The Acid Rain Program was delineated in Title IV of the CAA Amendments and required EPA to develop the program. EPA's final regulations were promulgated on

January 11, 1993, and included permit provisions (40 CFR Part 72), allowance system (Part 73), continuous emission monitoring (Part 75), excess emission procedures (Part 77), and appeal procedures (Part 78).

EPA's Acid Rain Program applies to all existing and new utility units except those serving a generator less than 25 MW, existing simple cycle combustion turbines (CTs), and certain non-utility facilities; units that fall under the program are referred to as affected units. The EPA regulations would be applicable to FGPP for the purposes for obtaining a permit and allowances, as well as emission monitoring. New units are required to obtain permits under the program by submitting a complete application 24 months before the date on which the unit commences operation (e.g., first fire).

The permit would require the units to hold SO_2 emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT or lowest achievable emission rate (LAER) for new units. An allowance is a market-based financial instrument that is equivalent to 1 ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

Under EPA's Acid Rain Program CEMs are required for opacity, SO_2, flow, NO_x, and CO_2 for coal-fired affected units. When an SO_2 CEM is used to monitor SO_2 mass emissions, a flow monitor is also required. CO_2 emissions must also be determined either through a CEM (e.g., as a diluent for NO_x monitoring). Alternate procedures, test methods, and quality assurance/quality control (QA/QC) procedures for CEM are specified (Part 75, Appendices A through I). The acid rain CEM requirements including QA/QC procedures are, in general, more stringent than those specified in the NSPS for Subpart Da. New units are required to meet the requirements by the later of January 1, 1995, or not later than 90 operating days or 180 calendar days after the unit commences commercial operation. There are specific notification requirements regarding EPA's Acid Rain Program.

TABLE 3-1
NATIONAL AND STATE AAQS, ALLOWABLE PSD INCREMENTS, AND SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	AAQS ($\mu g/m^3$) Primary Standard	AAQS ($\mu g/m^3$) Secondary Standard	AAQS ($\mu g/m^3$) Florida	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	PSD Class II Significant Impact Levels ($\mu g/m^3$) [b]
Particulate Matter[c] (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[a]	365	NA	260	5	91	5
	3-Hour Maximum[a]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[a]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[a]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	8-Hour Maximum[d]	157	157	157	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter (PM_{10}) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.
NA = Not applicable, i.e., no standard exists.

[a] Short-term maximum concentrations are not to be exceeded more than once per year.

[b] Maximum concentrations are not to be exceeded.

[c] On October 17, 2006, EPA promulgated revised AAQS for particulate matter. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour standard of 35 $\mu g/m^3$ (3-year average of 98th percentile) and an annual standard of 15 ug/m^3 (3-year average). The annual PM10 standard was revoked.
These standards have not yet been adopted by FDEP.

[d] 0.08 ppm; achieved when 3-year average of 99th percentile is 0.08 ppm or less. On July 18, 1007, EPA promulgated this standard, which has not yet been adopted by FDEP.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50; 40 CFR 52.21.
Chapter 62-204, F.A.C.

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES AND *DE MINIMIS* MONITORING CONCENTRATIONS

Pollutant	Regulated Under	Significant Emission Rate (TPY)	*De Minimis* Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter [PM(TSP)]	NSPS	25	10, 24-hour
Particulate Matter (PM_{10})	NAAQS	15	10, 24-hour
Nitrogen Dioxide	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Mercury	NESHAP	0.1	0.25, 24-hour

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below *de minimis* monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method established; therefore, no *de minimis* concentration has been established.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Short-term concentrations are not to be exceeded.

[b] No *de minimis* concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

Sources: 40 CFR 52.21; Rule 62-212.400.

TABLE 3-3
MAXIMUM EMISSIONS DUE TO FGPP COMPARED TO THE PSD SIGNIFICANT EMISSION RATES

	Pollutant Emissions (TPY)		
Pollutant	**Potential Emissions from FGPP[a]**	**Significant Emission Rate**	**PSD Review**
Sulfur Dioxide	3,049	40	Yes
Particulate Matter [PM(TSP)]	1,283	25	Yes
Particulate Matter (PM_{10})	1,024	15	Yes
Nitrogen Dioxide	3,827	40	Yes
Carbon Monoxide	11,442	100	Yes
Volatile Organic Compounds	260	40	Yes
Lead	0.2	0.6	No
Sulfuric Acid Mist	305	7	Yes
Total Fluorides	17.5	3	Yes
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	0.09	0.1	No

Note: NEG = Negligible.

[a] See Table 2-7.

TABLE 3-4
PREDICTED NET INCREASE IN IMPACTS DUE TO FGPP COMPARED TO PSD *DE MINIMIS* MONITORING CONCENTRATIONS

Pollutant	**Concentration (µg/m^3) Predicted Increase in Impacts**[a]	***De Minimis* Monitoring Concentration**
Sulfur Dioxide	5.2	13, 24-hour
Particulate Matter (PM_{10})	6.9	10, 24-hour
Nitrogen Dioxide	0.69	14, annual
Carbon Monoxide	42	575, 8-hour
Volatile Organic Compounds[b]	260 TPY	100 TPY

[a] See Section 6.0 for air dispersion modeling results.

[b] VOCs emissions are used as the PSD monitoring concentration threshold for O_3.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 INTRODUCTION

4.1.1 APPLICABILITY

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may potentially be emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, SO_2, PM/PM_{10}, CP, VOCs, fluorides, and SAM.

This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to the BACT analysis is based on the regulatory definitions of BACT, as well as consideration of EPA's current policy guidelines requiring a top-down approach. A BACT determination requires a site-specific analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies (see Rule 62-212.400, F.A.C.).

4.1.2 NEW SOURCE PERFORMANCE STANDARDS

The ultra-supercritical boilers will be subject to emission limitations under 40 CFR 60, Subpart Da, which limits NO_x, SO_2, and PM emissions from electric utility generating units that commence construction after February 28, 2005, capable of combusting more than 73 MW (250 MMBtu/hr) heat input using fossil fuel (71 FR 9866). The NSPS emission limit for PM from such units is 0.14 lb/MWhr (gross energy) or 0.015 lb/MMBtu. As an alternative, PM may be limited to 0.03 lb/MMBtu and 99.8-percent reduction from uncontrolled PM level when combusting solid fuel. The PM emissions from FGPP will be less than 0.11 lb/MW-hr or 0.013 lb/MMBtu, thus meeting the NSPS limit. The NSPS limits SO_2 emissions to 1.4 lb/MW-hr or 95-percent reduction, based on a 30-day rolling average. FGPP is designed to achieve an SO_2 emissions rate of less than 0.33 lb/MWhr (0.04 lb/MMBtu) on a 30-day rolling average and a control efficiency of greater than 95 percent, thus meeting the NSPS limits. Subpart Da limits NO_x emissions to 1.0 lb/MW-hr (gross energy output) based on 30-day rolling average. FGPP's NO_x emission rate will be less than 0.41 lb/MW-hr (0.05 lb/MMBtu) on a 30-day rolling average. Visible emissions are limited to 20-percent opacity (6-minute average) except up to 27-percent opacity is allowed for one 6-minute period per hour. FGPP will meet this opacity limit.

The auxiliary boilers are subject to the NSPS codified in 40 CFR 60, Subpart Db, Standards for Performance for Industrial-Commercial-Institutional Steam Generating Units for emissions of SO_2, PM, and NO_x. This NSPS is applicable to steam-generating units with a heat input capacity of greater than 100 MMBtu/hr commencing construction after February 28, 2005 (71 FR 9866). To reduce emissions of SO_2 and PM, FGPP will use 0.0015-percent sulfur distillate oil, which is less than the NSPS requirement of 0.3 percent, defined as very low-sulfur fuel. The NSPS opacity limit of 20 percent as a 6-minute average, except for one 6-minute period not to exceed 27- percent opacity, will be met and demonstrated using continuous opacity monitors. The NO_x emissions from the boiler will be 0.12 lb/MMBtu, which is less than the Subpart Db emission limit for emissions NO_x of 0.2 lb/MMBtu (high-heat-release rate units) although not applicable since the capacity factor will be 10 percent.

EPA promulgated final regulations establishing NSPS for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) (71 FR 39154; July 11, 2006). Under this regulation, engine manufacturers are required to produce engines that will meet the emission limiting standards for the life of the engine. In addition, fuel requirements have been established. The engines proposed for FGPP will utilize fuel with a sulfur content of 0.0015 percent and obtain the certifications necessary that demonstrate that the NSPS in 40 CFR Part IIII will be met. Thus, the emergency generators and fire pump engine will meet the NSPS requirements.

The material handling operation associated with FGPP will be required to meet two different NSPS. For coal crushing and transferring, the NSPS codified in 40 CFR Part 60, Subpart Y; Standards of Performance for Coal Preparation Plants, will apply. The emission limits for this NSPS is 20-percent opacity for coal processing and conveying equipment and coal storage. The coal crushers and transfer equipment will be enclosed with vent filters in several locations to limit PM emissions with resulting opacity less than 20 percent.

The grinding of limestone for use in the wet FGD system is subject to the NSPS codified in 40 CFR Part 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants. The NSPS PM emission limit is 0.05 gr/dscm and 7-percent opacity. Limestone will be ground in an enclosed wet ball mill with no stack or vent, resulting in negligible PM emissions that will meet the NSPS requirements.

4.1.3 BEST AVAILABLE CONTROL TECHNOLOGY METHODOLOGY

BACT review is required under FDEP rules and EPA regulations pertaining to PSD. FDEP has adopted PSD rules in Rule 62-212.400, F.A.C. BACT is applicable to all pollutants for which PSD review is required and is pollutant specific. It is an emission limitation that is based on the maximum degree of reduction for each regulated pollutant, which is determined to be appropriate after taking into account energy, environmental, economic impacts, and other costs. BACT cannot be any less stringent than the federal NSPS applicable to the source under evaluation.

The FDEP performs BACT reviews based on EPA's regulations and guidance in which the most stringent control alternatives are evaluated to identify the "best available control technology" and a related appropriate emissions limitation for each pollutant requiring a BACT determination. This procedure is referred to as the "top down" approach. This approach in EPA guidance consists of the following five steps (*New Source Review Workshop Manual-Draft*, 1990):

1) Identification of potentially applicable control technologies;
2) Evaluation of the technical feasibility of installing the identified control technologies at the Site;
3) Ranking of the feasible control technologies based on their effectiveness;
4) Evaluation of the energy, environmental and economic impacts of the feasible control options; and
5) Selection of BACT based on consideration of the above factors.

FGPP's PSD application requires a BACT review for emissions of the following pollutants from the ultra-supercritical boilers: nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), combustion products (carbon monoxide or CO and volatile organic compounds or VOCs), sulfuric acid mist (SAM), and fluoride (F^-). In addition, a BACT analysis is required for PM emissions from the cooling tower, fugitive particulate emissions from material handling, and emissions of certain specific pollutants from particular auxiliary equipment (the auxiliary boiler, emergency generators, and a diesel fire pump). This section provides the required BACT analyses for these emissions. It is based on a comprehensive review of recent BACT determinations for new coal-fired units similar to those proposed for FGPP. For each of the pollutants, a specific top-down analysis is based on the five steps to determine BACT. In each case, a BACT is an emission limitation that meets the maximum degree of emission reduction after taking into account FGPP's specific energy, environmental and economic impacts and other costs, as well as consideration of the application of the technologies was proposed.

Appendix B, Tables B-1 through B-8, sumarize the BACT determinations made to other similar projects with regard to each pollutant – NO_x, SO_2, PM/PM_{10}, SAM, CO, VOCs, and fluorides. The projects include supercritical and conventional pulverized coal-fired steam-generating units since these units are comparable to FGPP. These tables were developed by reviewing the EPA BACT/LAER Clearinghouse information and obtaining specific permit information on each project. The projects consist of supercritical and conventional pulverized coal-fired steam-generating units since the potentially applicable control technologies are feasible for these type units.

4.2 BEST AVAILABLE CONTROL TECHNOLOGY – BOILERS

4.2.1 OVERVIEW OF PROPOSED BACT

A summary of the emission rates proposed as BACT and compliance methods is presented in Table 4-1. The proposed BACT emission rates for FGPP are consistent with recent BACT determinations. Table 4-2 presents a summary of the economic, environmental, and energy impacts of the proposed BACT control technology for the ultra-supercritical boilers. The following sections provide BACT evaluations for NO_x, PM/PM_{10}, SO_2, SAM, fluorides and combustion products (CO and VOC). As will be evident, the emission rates proposed for FGPP are consistent with recent PSD determinations for other similar projects. In particular, with regard to each pollutant, the proposed emission rate is less than or equal to the median rate for recent BACT determinations.

4.2.2 NITROGEN OXIDES

Identification of Potentially Applicable Control Technologies

The BACT analysis was performed based on those available and feasible control technologies that can provide the maximum degree of emission reduction for NO_x emissions. Emissions of NO_x are produced by the high-temperature reactions of molecular nitrogen and oxygen in the combustion air and by fuel-bound nitrogen with O_3. The former is referred to as thermal NO_x while the latter is referred to as fuel-bound NO_x. The relative amount of each depends on the combustion conditions and the amount of nitrogen in the fuel. Formation of thermal NO_x depends on the combustion temperature and becomes rapid above 1,400 degrees Celsius (°C) (2,550°F). The equations developed by Zeldovich are recognized as the reactions that form thermal NO_x:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

The important parameters in thermal NO_x formation are combustion temperatures, gas residence time, and local stoichiometric ratio of fuel and air. Fuel-bound NO_x, although with most fossil fuels are usually small compared to thermal NO_x, is more readily formed by the nitrogen in the fuel that reacts with combustion air. Another mechanism for NO_x formation is the reaction of molecular nitrogen with free hydrogen (H) radicals. This mechanism is known as "prompt NO_x" and occurs within the combustion zone with the following major reactions:

$$N_2 + CH \rightarrow HCN + N$$
$$N + O_2 \rightarrow NO + O$$

The contribution of prompt NO_x to overall NO_x levels is relatively small (less than 5-percent). The primary ways to reduce NO_x emissions are through either combustion process control or through catalytic or noncatalytic reactions.

Combustion controls are the primary engineering choice in reducing NO_x concentrations within the boiler. Combustion controls include low NO_x burners (LNB) and over-fire air OFA). Such controls are considered "pollution preventing", since the formation of NO_x is limited in the combustion process. A combustion technology referred to as reburn has also been installed as retrofits on existing units to reduce NO_x emissions.

Reburn involves using fuel as a reducing mechanism in the combustion process to remove NO_x. The process involves three basic components. The first is the primary combustion area where 80 to 85 percent of the fuel is burned. In this area, fuel is fired typically using the existing burner systems, which also can be low-NO_x burners. In the second area, downstream of the primary combustion zone, remaining fuel is introduced to form a slightly fuel rich combustion zone. This area is often referred to as the reburn zone, where hydrocarbon compounds are formed that react with nitrogen oxide, the primary form of NO_x in combustion processes. The reactions of these hydrocarbon radicals and nitrogen oxide ultimately form nitrogen, which is the opposite of the NO_x formation process (i.e., Zeldovich equation). The third area, downstream of the reburn zone, is often referred to as the burnout zone where combustion air is added to combust the remaining hydrocarbon compounds. Overall the combustion process is typically fuel lean.

Reburn has been demonstrated using natural gas, coal, residual oil, and Orimulsion®. Reductions in NO_x from 40 to 70 percent have been demonstrated with this wide variety of fuels.

Post combustion NO_x control processes include catalytic and non-catalytic conversion of NO_x, typically to nitrogen. Non-catalytic processes, referred to as selective non-catalytic reduction, use ammonia or urea injection at high temperatures, generally about 1,800°F. These technologies, which can achieve from 30- to 80-percent NO_x removal (depending on the fuel), are primarily applicable to boilers that can maintain a relatively constant temperature for the reaction. The primary applications have been on circulating fluidized bed boilers.

The catalytic NO_x removal process that has been demonstrated and proven is selective catalytic reduction (SCR). SCR is a widely used post-combustion NO_x-control technology that has been used on a variety of fuels (e.g., coal, natural gas, residual and distillate oil, and Orimulsion®) and applications (e.g. fossil steam units, combined cycle units, diesel engines and simple cycle gas turbines). Developing technologies include processes that either combine removal of various pollutants or specifically target the removal of NO_x. Such technologies, that include Electro-Catalytic Oxidation™ and SO_x-NO_x-RO_x Box and THERMALONOx™, have future promise but have not been demonstrated on large (>100 MW) thermal power facilities.

The fundamental reaction for SCR was noticed by the selective reaction of ammonia with NO in the presence of a catalyst and excess oxygen that was discovered by Engelhard Corporation in 1957. SCR technology was commercially developed in Japan and used there on a continuing basis for the first time. In an SCR process, either anhydrous or aqueous ammonia is injected into the flue gas upstream of catalysts. The catalysts are arranged in modules set up into single or multiple stages. The selective reduction reactions occur at temperatures between 650 and 800°F on the surface of the SCR catalysts to produce molecular nitrogen gas and water. The reactions are as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_20$$

SCR catalysts consist of two types: base metal oxides and zeolite. In an SCR system using a base metal oxides catalyst, either vanadium or titanium is embedded into a ceramic matrix structure; the zeolite catalysts are ceramic molecular sieves extruded into modules of honeycomb shape. Catalysts exhibit advantages and disadvantages in terms of exhaust gas temperatures, ammonia/NO_x ratio, and exhaust gas O_3 concentrations for optimum control. A common disadvantage for all catalyst systems is the limited temperature window where the NO_x reduction process takes place. Operating outside this temperature range results in failure to remove NO_x and/or harm to the catalyst system. Chemical poisoning can occur at lower temperature conditions, while thermal degradation can occur at higher temperatures plus NO_x can be produced at higher temperatures. Reactivity can only be restored through catalyst replacement. Sufficient O_2 is required to ensure successful reactions. For most SCR applications that have been effective, O_2 concentrations have been in excess of 2 percent of flue gas.

The reaction occurs typically between about 320 and 400°C (600 and 750°F). These temperatures occur after the economizer in a structure containing the ammonia injection grid followed by the SCR catalyst.

Evaluation of Technically Feasible Control Alternatives

Low NO_x burners (LNB) and over-fire air (OFA) are the initial choice in reducing NO_x from the combustion process. SNCR and reburn are feasible and available but their application has been limited to existing units with lower NO reduction rates ranging between 30 to 80 percent. SCR can achieve NO_x reduction in excess of 80 percent. Most recent permits issued for coal-fired power plants have required the use of combustion controls combined with SCR to control NO_x because these controls are generally available, technically feasible and provide the maximum degree of emission reduction. Appendix B, Table B-2, presents the emission rates for similar projects. In all these projects, combustion controls and SCR are used.

Ranking of Feasible Control Alternatives

Combustion controls and SCR will achieve the maximum degree of NO_x emission reduction. SNCR and reburn will not achieve an emission rate as low as that being proposed for FGPP. Combustion controls, while an effective means of initially reduction NO_x formation will not achieve the maximum emission reduction.

Evaluation of Energy, Environmental and Economic Impacts of Feasible Technologies

Economic

The total estimated capital, annualized, and incremental costs of SCR are based on budgetary cost estimates. The total estimated capital, annualized, and incremental costs are summarized in Table 4-3. The capital cost for one 980-MW unit is about $43 million with an annualized cost of about $9.7 million. The cost effectiveness is $853 per ton of NO_x removed based on emissions from the boiler of 0.35 lb/MMBtu. The NO_x emissions from the boiler are inherent in the combustion design of the boiler and would include LNB and over-fire air.

Environmental

The maximum predicted NO_x impact of FGPP with SCR is 0.7 $\mu g/m^3$, considerably below the NO_2 PSD Class II increment of 25 $\mu g/m^3$ (annual average) and the AAQS of 100 $\mu g/m^3$ (annual average).

The addition of SCR will reduce NO_x emissions by at least 11,432 TPY per unit. The combustion controls will prevent the formation of 13,337 TPY of NO_x based on a hypothetical uncontrolled emission rate from the boiler of 0.7 lb/MMBtu and a boiler outlet NO_x emission of 0.35 lb/MMBtu. Together, these technologies reduce NO_x emissions by about 24,400 TPY or over 90 percent reduction.

The SCR system has recognized collateral benefits for the conversion of elemental mercury (Hg) to an oxidized form typically mercuric chloride ($HgCl_2$). Elemental Hg is difficult to remove in downstream pollution control equipment. The oxidized form is readily collected in wet FGD systems.

The electrical energy required to run the SCR system and the pressure drop from the SCR catalyst will reduce the available power from FGPP that would otherwise be available to FPL customers. To replace this lost energy, additional emissions from FGPP would occur. The pressure drop is a result of the catalyst modules located in the exhaust gas stream. The pressure drop to reduce NO_x to 0.05 lb/MMBtu is estimated to 8 inches of water gauge. This pressure drop requires more fan power, which would otherwise be available to the electrical system. Based on the amount of megawatts per hour required to provide the fan and electric energy, the additional emissions would be 78 TPY. This amount of increased emissions is low compared to the amount of NO_x reduced.

SCR will require the construction and maintenance of a storage vessel for ammonia for use in the reaction. The construction of ammonia storage facilities triggers the application of at least three major standards: Clean Air Act (Section 112), Occupational Safety and Health Administration (OSHA) 29 CFR 1910.1000, and OSHA 29 CFR 1910.119. FGPP would comply with the applicable requirements under these standards.

Energy

Energy penalties occur with SCR. With SCR, the output is reduced due to the pressure drop and there are energy requirements to operate the SCR system.

The energy required to operate the SCR equipment would be about 13,000 megawatt-hours (MWh) per year per unit, while the energy required to overcome the pressure drop requires 35,700 MWh. Taken together, the total energy requirement is 48,600 MWh. This is about 0.5 percent of the gross generation. Energy is also required to atomize the ammonia, estimated to be 9,000 MMBtu/yr. This is only about 0.012 percent of the heat input of the unit.

Selection of BACT and Rationale

The identification, technical evaluation and ranking and of the available control technologies clearly indicate that combustion controls and SCR provide the maximum degree of emission reduction. The evaluation of the energy, environmental and economic impacts demonstrate that this combination of controls are cost effective and do not have collateral environmental impacts greater than the benefit of reduction NO_x.

The proposed technologies to achieve the emission proposed as BACT for NO_x is advanced combustion technology and SCR. This combination of the technology can achieve the maximum amount of emission reduction available, technically feasible and demonstrated for FGPP. SCR is feasible and reasonable based on the economic, environmental, and energy impacts. An emission rate of 0.05 lb/MMBtu is proposed as BACT and is equal to or less than the BACT emission rates established as BACT for similar projects

4.2.3 PARTICULATE MATTER

Identification of Potentially Applicable Control Technologies

Introduction

There are two primary methods of PM formation in the proposed supercritical boilers and associated control equipment: 1) fly ash from coal combustion in the boiler, and 2) solids from reaction products introduced in the FGD system. The latter is reduced by mist eliminators and further PM removal (see Subsection 4.2.5, Sulfuric Acid Mist).

Combustion of coal in a pulverized coal-fired boiler creates ash, which is the non-combustible portion of the fuel. The ash is solid and therefore is classified as PM. A portion of this PM, approximately 20 percent, falls to the bottom of the boiler as bottom ash and is removed by the bottom ash system. The majority of the PM, approximately 80 percent, is fly ash and is entrained by the flue gases leaving the boiler. The majority of this fly ash is then collected by the flue gas PM removal system.

Inertial separators such as mechanical cyclones and wet scrubbers such as venture and spray chambers were historically used for particulate control prior to the 1970's. These devices have typically achieved particulate removal in the range 60 to 90 percent. Recent coal fired units have not used these devices since the emission rates would be at levels that could not achieve the NSPS.

ESPs and fabric filters are the most effective PM-control devices being successfully applied to modern coal-fired power plants. PM removal efficiencies of these devices can be greater than 99.8 percent. Both devices are also highly effective in controlling PM_{10} emissions.

ESPs

In an ESP, a high-voltage electric field is produced to impart an electric charge to the solid particles in the flue gas stream. The pulsating direct current voltage in the range of 20,000 to 100,000 volts is used to ionize the gas stream, known as corona. The ions produced using a negative corona, are attracted to the particles while traveling in the ionized gas stream. These particles are then removed from the gas stream by migrating toward the collecting electrode. Rapping mechanisms, that are operated intermittently, dislodge the collected particles, which subsequently fall into a hopper. ESP performance is highly dependent on the electrical characteristics or resistivity of the particle or aerosol to be collected.

ESP performance is dependent on a number of factors, which influence the resistivity of the particle. These factors include the particle composition, flue gas characteristics, particle size distribution, and particle loading. These parameters can vary during normal operation and can influence ESP performance when gas streams come directly from the boiler.

Fabric Filters

In a fabric filter, PM is removed from the flue gas as it passes through a fabric filter media such as woven cloths or felts; hence the term "fabric filter." The filters are normally arranged as a number of cylinders or tubes (commonly referred to a "bags") through which the flue gas is directed. The filters are contained in a housing which has gas inlets and outlets. The flue gas enters the cylindrical filter from the bottom and flows upward, from either the inside of the cylinder to the outside or the opposite depending upon the design. Particulate collection occurs through several mechanisms, including gravitational settling, direct impaction, inertial impaction, diffusion, and electrostatic attraction. When the pressure drop reaches a predefined level, a section of the filters is taken offline for cleaning. Various methods are used to clean the bags in the fabric filter. The three general types of cleaning are shaker cleaning, pulse-jet cleaning, and reverse-air cleaning. All three types of cleaning methods ensure the fabric filter achieves the same low emission rates.

The shaker cleaning is accomplished by taking the bags off-line, shaking the bags of the fabric filter, and then deflating the bag by inducing a vacuum. The PM collected on the bags is dislodged and then falls into the collection hoppers at the bottom of the fabric filter.

In the pulse-jet method of cleaning, cleaning is accomplished off-line by directing a short burst of compressed air inside the filter bags. This burst produces a shock wave, which travels down the length of the bag, dislodging the accumulated dust cake. The collected PM then falls into the hoppers located below the bags. This is currently the best practice for cleaning.

In reverse air fabric filters, the PM is collected on the inside of the filter bags. Cleaning is accomplished by introducing a reverse flow of air through the bags. This causes the bag to collapse, thereby dislodging the filter cake. The dislodged PM falls into the collection hoppers for disposal.

Evaluation of Technically Feasible Control Alternatives

ESPs and fabric filters are available, technically feasible and demonstrated as effective PM control devices for coal fired units. Mechanical collectors and wet scrubbers are feasible technologies but their application for new coal fired units has not occurred for over 30 years.

Ranking of Technically Feasible Control Alternatives

Both fabric filters and ESPs are highly effective in controlling PM_{10} emissions and are considered equivalent in PM removal. Other technologies, such as mechanical collectors and wet scrubbers, have not demonstrated equivalent levels of control for PM. As a result, ESPs and fabric filters are considered equivalent to achieve an emissions rate potentially applicable as BACT for FGPP.

Evaluation of Energy, Environmental and Economic Impacts of Feasible Technologies

Economic

The total estimated capital, annualized, and incremental costs for an ESP are summarized in Tables 4-4 and 4-5, shown with and without ash disposal cost, respectively. The capital cost for one 980-MW unit is about $67 million with an annualized cost of about $10 million if ash can be sold (no net cost for disposal). If ash is stored onsite, the annualized cost is $13.5 million. The cost effectiveness ranges from $39 to $52 per ton of PM removed. The difference depends on the amount of ash that can be recycled as a pozzolin material.

The total estimated capital, annualized, and incremental costs for a fabric filter are summarized in Table 4-6 and 4-7, shown with and without ash disposal cost respectively. The capital cost for one 980 MW unit is $67 million with an annualized cost of $11 million if ash can be sold (no net cost for disposal). If ash is stored onsite the annualized cost is $14 million. The cost effectiveness ranges for $45 to $55 per ton of PM removed. The lower cost effectiveness for the ESP is a result of the much higher pressure drop for the fabric filter.

Environmental

The maximum predicted PM impact of FGPP with an ESP or baghouse is considerably below the PSD Class II increments and the AAQS of 100 $\mu g/m^3$.

The addition of ESP or fabric filter will reduce PM emissions by 260,000 TPY per unit. There is also a reduction in HAPs of about 3 TPY.

The electrical energy required to run the ESP system or the pressure drop from a fabric filter will reduce the available power from FGPP. The pressure drop is a result of the filter bags located in the exhaust gas stream. The pressure drop to reduce PM to 0.013 lb/MMBtu is estimated to 8 inches of water gauge. This pressure drop requires more fan power. The ESP is a high-voltage device and requires electrical energy. The pressure drop of the ESP will be generally low. The lost power from electrical usage or back pressure would otherwise be available to the electrical system. To replace this lost energy, additional emissions from FGPP would occur. Based on the amount of megawatts per hour required to provide the fan and electric energy, the additional emissions would be 24 TPY for the ESP and 57 TPY for the fabric filter. While amount of increased emissions is low compared to the amount of PM reduced, the fabric filter results in slightly more emissions from lost energy.

The fabric filter has an advantage over an ESP as it relates to additional removal of pollutants when sorbents are injected prior to the control device. Sorbents, such as activated carbon, are in the form of fine particles that can react in the gas stream to remove pollutants, such as mercury. With a fabric filter, the filter cake developed on the bags that includes the sorbent will continue to remove pollutants until the bags are cleaned. During this period, additional removal is achieved that could not be accomplished in an ESP. As a result, the use of a fabric filter has additional pollutant removal co-benefits beyond PM removal.

Energy

Energy losses will occur with ESP/fabric filter. With a fabric filter, the output is reduced due to the pressure drop; while with an ESP, there are high energy use requirements.

The energy required to operate an ESP would be about 15,000 MWh per year per unit. This is about 0.16 percent of the gross generation. The energy required to operate a fabric filter would be about 35,700 MWh per year per unit. This is about 0.39 percent of the gross generation.

Selection of BACT and Rationale

The identification, technical evaluation and ranking and of the available control technologies clearly indicate that ESPs and fabric filters provide the maximum degree of emission reduction for PM emissions from coal fired units. The evaluation of the energy, environmental and economic impacts demonstrate that these controls are cost effective and do not have collateral environmental impacts greater than the benefit of reduction PM.

While both an ESP and fabric filter can achieve the maximum amount of PM emission reduction available, the fabric filter has additional benefits when sorbents are used. A fabric filter is feasible and reasonable based on the economic, environmental, and energy impacts. An emission rate of 0.013 lb/MMBtu is proposed as BACT given the evaluations and recent BACT decisions on other similar projects. The proposed emission rate is equal to emission rates established for similar projects (refer to Appendix B, Table B-3).

4.2.4 SULFUR DIOXIDE

Identification of Potentially Applicable Control Technologies

Introduction

Sulfur compounds are produced in boilers firing fossil fuels by the combustion process in which complete oxidation of the fuel-bound sulfur occurs, forming primarily SO_2, with smaller quantities of sulfur trioxide (SO_3). The amount of SO_2 emissions is directly proportional to the sulfur and sulfate content in the fuel. Reducing SO_2 emissions by boiler modification is not feasible because combustion processes do not affect SO_2 emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before complete combustion of carbon, the most abundant element in fossil fuel. For pulverized coal-fired utility boilers, SO_2 emission reduction is typically accomplished by treating the post-combustion flue gas with a FGD process.

Standard FGD processes for pulverized coal-fired boilers are back-end equipment of either the wet or dry type; these are often referred to as wet and dry scrubbing, respectively. Since the early 1970s, FGD has been used extensively in the United States to control SO_2 emissions from coal-fired power plants. Indeed, the use of FGD systems was, in effect, mandated for pulverized coal-fired power plants with the promulgation of the NSPS for electric utility steam generating units (i.e., 40 CFR Part 60, Subpart Da), which required minimum reductions between 70 and 90 percent in the potential combustion concentration of SO_2.

Dry FGD

In a dry FGD process, the flue gas entering the scrubber contacts an atomized slurry of either wet lime or wet sodium carbonate (Na_2CO_3) sorbent. The exact mechanisms for the absorption of gaseous SO_2 and the formation of alkaline salts are complex. Overall, the SO_2 gas reacts with lime or sodium sorbent to initially form either calcium sulfite ($CaSO_3 \bullet \frac{1}{2}H_2O$) or sodium sulfite ($Na_2SO_3$). Upon further oxidation or SO_2 absorption enhanced by the drying process, the sulfite salts transform into calcium sulfate ($CaSO_4 \bullet 2H_2O$) or sodium sulfate solids. A typical dry scrubber will use lime as the reagent because it is more readily available than sodium carbonate and the sodium-based reactions produce a soluble by-product that requires special handling.

Lime slurry is injected into the dry scrubber chamber through either rotary atomizers or pressurized fluid nozzles. Rotary atomizers use centrifugal energy to atomize the slurry. The slurry is fed to the center of a rapidly rotating disk or wheel where it flows outward to the edge of the disk. The slurry is atomized as it leaves the surface of the rapidly rotating disk.

Fluid nozzles use kinetic energy to atomize the slurry. High-velocity air or steam is injected into a slurry stream, breaking the slurry into droplets, which are ejected at near-sonic velocities into the spray-drying chamber. Slurry droplets of comparable size can be obtained with both fluid nozzles and rotary atomizers, minimizing differences in performance due to atomizer type. The nozzle location relative to the flow, however, can be different depending on the particular design.

The moisture in the lime slurry evaporates and cools the flue gas, and the wet lime absorbs SO_2 in the flue gas and reacts to form liquid-solid phase salts that are then dried into insoluble crystals by the thermal effect of the flue gas. The dry scrubber chamber is designed to provide sufficient contact and residence time to complete this reaction process. The prolonged residence time in the chamber is typically designed for 10 to 15 seconds. Sufficient contact between the flue gas and the slurry solution is maintained in the absorber vessel, allowing the absorbing reactions and the drying process to be completed.

The particulate exiting the dry scrubber contains fly ash, dried calcium salts, and dried unreacted lime. The moisture content of the dried calcium salt leaving the absorber is about 2 to 3 percent, eventually decreasing to about 1 percent downstream. The simultaneous evaporation and reaction in the spray drying process increases the moisture and particulate content of the flue gas and reduces the flue gas temperature.

In the dry scrubber, the amount of water used is optimized to produce an exit stream with "dry" particulates and gases with no liquid discharge from the scrubber. The flue gas temperature exiting the dry scrubber is typically 18 to 30°F above adiabatic saturation. The "dry" reaction products and coal fly ash are removed from the flue gas by a particulate collection device located downstream of the scrubber. This differs from the wet scrubber system, wherein the slurry leaving that system must be dewatered and the gas is cooled to adiabatic saturation temperature. Moreover, in the wet process, the particulate control device is located upstream of the scrubber. The dry byproduct from the dry scrubber system is generally not marketable since the byproducts includes a fly ash and reacted SO_2 and calcium compounds. In contrast, the wet limestone FGD system can produce a marketable byproduct (i.e., gypsum).

Key design and operating parameters that can significantly affect dry scrubber performance are reagent-to-sulfur stoichiometric ratio, slurry droplet size, inlet water content, residence time, and scrubber outlet temperature. An excess amount of lime above the theoretical requirement is generally fed to the dry scrubber to compensate for mass transfer limitations and incomplete mixing. Droplet size affects scrubber performance. Smaller droplet size increases the surface area for reaction between lime and acid gases and increases the rate of water evaporation. A longer residence time results in higher chemical reactivities, and the reagent-SO_2 reaction occurs more readily when the lime is wet. The scrubber outlet temperature is controlled by the amount of water in the slurry. Typically, effective utilization of lime and effective SO_2 removal occur at temperatures close to adiabatic saturation, but the flue gas temperature must be kept high enough to ensure that the slurry and reaction products are adequately dried prior to the particulate collection process.

The dry scrubber is located upstream of the particulate control device, which is either an ESP or a fabric filter (baghouse) system. The baghouse is generally preferred when using a dry scrubber FGD system over the ESP because it provides additional SO_2 and acid gas removal. When a baghouse is used, a layer of porous filter cake is formed on the surface of the filter bags. This filter cake contains unspent reagent, which provides a site for additional FGD since all flue gases also pass through the filter bags.

Based on BACT determinations previously issued, the dry scrubber FGD system can achieve 70- to 93-percent SO_2 removal for coal-fired boilers, with the majority of pulverized-coal boilers designed for 93-percent removal. Higher removal efficiencies of greater than 90 percent can be achieved by maintaining an optimal ratio of reagent and SO_2 gas.

Wet FGD

The primary technology that has been developed and installed to remove SO_2 at high efficiencies (95 percent or greater) from thermal power plants has been wet scrubbing. Other SO_2 control processes either have lower removal efficiencies than wet scrubbing or are in the developmental and demonstration stage. For example, there are several SO_2 control processes have been tested at bench-, pilot-, and/or small-scale application but has neither been demonstrated at full-scale nor commercially available at the size required for FGPP. Such technologies include SO_x-NO_x-RO_x Box and Electro-Catalytic Oxidation^{TM}.

Wet scrubbing is a gaseous- and liquid-phase reaction process in which the SO_2 gas is transferred to the scrubbing liquid under saturated conditions. The wet scrubbing process usually involves a liquid waste stream and slurry as by-products. Therefore, a wastewater treatment and by-product disposal system is generally associated with a wet scrubbing system.

Wet scrubbing systems include three different types, which are classified by the reagents used in the scrubbing process. The type of reagent influences the scrubber design, the quantity and type of wastes produced, and the type of disposal system required. Sodium-based, calcium-based, or dual-alkali-based chemicals are used; these systems are referred to as sodium-based, wet lime/limestone scrubbers, or dual-alkali.

The sodium scrubbing systems use either a sodium hydroxide (NaOH) or a sodium carbonate (Na_2CO_3) wet scrubbing solution to absorb SO_2 from the flue gas. Because of the high reactivity of the sodium alkali sorbent compared to the lime or limestone sorbents, these systems are characterized by a low liquid-to-gas ratio. The SO_2 gas reacts with the hydroxide or carbonate to form sulfite (e.g., Na_2CO_3) initially, then sulfate (Na_2SO_4) with further oxidation. Both sodium sulfite and sulfate are highly soluble; therefore, the final scrubber effluent is a mixture of sodium alkaline salt liquor that requires special disposal. Although these sodium-based systems are capable of achieving greater than 90-percent SO_2 reduction, they have not been used commercially on large utility boilers; therefore, these systems are considered unproven.

The dual-alkaline scrubbing process uses the sodium-based liquor to scrub the SO_2 from the flue gas initially, then calcium-based chemicals are used to regenerate the sodium hydroxide or Na_2CO_3 solution. Both the sodium-based and the dual alkali-based scrubbing systems were developed many years ago to address the inherent fouling problem that was often experienced with conventional lime/limestone wet scrubber systems. Secondly, it was believed that the sodium-based or the dual-alkali-based systems could achieve higher percent removals of SO_2 due to higher reactivity. The primary reasons for not using the sodium-based system are the cost of premium chemicals, the lack of availability of sodium-based chemicals, the highly alkaline waste liquid produced, and lack of utility boiler experience.

The sodium-based and the dual-alkaline-based scrubbing processes are no longer commercially available from the primary supplier, FMC Corporation. Other suppliers of the sodium-based or dual-alkali-based systems, Ontario Hydro and General Electric Environmental Systems, no longer recommend these systems to control coal-fired boilers over the improved lime/limestone wet scrubber. Neither the sodium-based scrubber nor the dual-alkali scrubber has been installed for any fossil fuel-fired facility in recent years. The last dual-alkaline system was supplied by General Electric (GE) over 20 years ago at the Newton Station in Illinois. The sodium-based and the dual-alkali scrubbing processes are generally considered technically unavailable. The Department of Energy is sponsoring a commercial demonstration of a sodium based process referred to as the Airnome Process. A 5-MW demonstration was completed in 2003 and future larger scale demonstrations are planned in the future. This process is in the development stage and not yet commercially available.

Development of the spray tower limestone FGD system operating at high liquid-to-gas ratios has produced levels of SO_2 removal as high as those of the dual-alkali-based system. Improved operating techniques have also eliminated the severe fouling problems experienced by the earlier lime/limestone scrubber systems.

The most widely used system for large-scale SO_2 removal is the calcium-based wet lime/limestone FGD system. Worldwide, there are over 200,000 MW of installed wet limestone FGD systems, which represents about 80-percent of FGD systems. The remaining 20-percent are sodium-based systems and spray-dryer lime systems. It is estimated that approximately 82 percent of the coal-fired capacity with FGD control in the United States is equipped with this wet limestone FGD technology.

Depending on whether lime or limestone is used, the SO_2 reacts with the hydrates or carbonates to form calcium sulfite (i.e., $CaSO_3 \bullet \frac{1}{2} H_2O$) initially, then sulfate (i.e., $CaSO_4 \bullet 2H_2O$) with further oxidation. The latter, known as wet limestone-forced oxidation FGD, involves blowing air into the slurry to force oxidation of calcium sulfate to almost 100 percent. This produces a marketable by-product (i.e., gypsum).

One version of the wet FGD technology is the spray tower. In this system, a slurry of atomized limestone is sprayed into a tall, vertical absorber tower through a series of nozzles. The flue gas enters at the bottom of the tower, passes vertically up through the spray droplets, and exits the vessel at the top.

The slurry is recirculated through the absorber system. This recirculation increases the scrubbing utilization of the limestone reagent. The scrubbing reaction produces calcium sulfite as the byproduct. Most systems oxidize the sulfite into calcium sulfate, which is easier to dewater. A bleedstream is taken off from the recycled slurry stream to purge the system of gypsum and avoiding buildup inside the spray tower. By-products and unreacted reagents in the bleedstream are dewatered using various equipment including thickeners (hydroclones), centrifuges, and vacuum filters. Dewatering can reduce the water content in the filtered by-product to as low as 10 to 15 percent by weight.

Wet scrubbing systems can use lime rather than limestone as the alkali reagent. Quick lime (calcium oxide) is slaked with water to form hydrated lime (calcium hydroxide). The slurry of calcium hydroxide and water is then sprayed into the spray tower. This alternative of using lime instead of limestone is less attractive economically because the cost of either quick lime or hydrated lime is much higher than the cost of limestone. While a limestone system requires more initial capital costs for auxiliary equipment (i.e., limestone ball mill and conveyors), the lower operating cost of the reagent provides a substantial annual savings for wet limestone FGD systems over the use of lime. This is especially beneficial for a facility using medium- and high-sulfur coals, where considerably more reagent chemicals are needed.

In conventional wet limestone FGD systems, several additives have been used to enhance SO_2 removal efficiencies. The majority of additives, both organic and inorganic, have been used to bring the performance of the FGD system up to the original performance requirements. The organic additives include various mixtures of organic acids that include dibasis acid and formac acid. Magnesium, added as magnesium-lime has been successfully used to enhance performance. With the advancement of wet FGD designs, efficiencies of 98 percent can be achieved by refinements in design including critical elements of absorbers, materials, and control systems. Additives can still play a role but their use is primarily focused on emergency condition operation, corrosion inhibition, scaling, and by-product handling.

Evaluation of Technically Feasible Control Alternatives

Dry and wet FGD system are available, technically feasible and demonstrated as effective SO_2 control devices for coal fired units. Of the wet FGD systems, wet limestone FGD systems have been the primary selection for coal fired units.

Ranking of Technically Feasible Control Alternatives

Wet limestone will achieve the maximum degree of SO_2 emission reduction with removal efficiencies of 98 percent. Dry FGD systems will not achieve as great an emission reduction with SO_2 removals in the range of 95 percent. Dry FGD systems are typically used with very low sulfur coals and would not achieve an emission rate as low as that being proposed for FGPP. In addition, wet FGD systems have additional collateral environmental benefits of achieving removal of other gases (reactive mercury, hydrogen chloride and fluorides).

Wet limestone FGD systems have been demonstrated to achieve high SO_2 removal efficiencies of 98 percent or more and have been associated with emission limits that have been accepted as BACT. This technology is technically feasible for FGPP and provides the maximum degree of emissions reduction. For FGPP, the maximum emissions of SO_2 being proposed as BACT is 0.04 lb/MMBtu using wet limestone FGD and is equal to or lower than BACT emission limits that have been established for similar projects.

Evaluation of Energy, Environmental and Economic Impacts of Feasible Technologies

Economic

The total estimated capital, annualized, and incremental costs are summarized in Tables 4-8 and 4-9, shown with and without gypsum recycling, respectively. The capital cost for one 980-MW unit is \$146 million with an annualized cost of about \$33 million if gypsum can be recycled (no net cost for disposal). If gypsum is stored onsite, the annualized cost is about \$39 million. The cost effectiveness ranges from \$275 to \$319 per ton of SO_2 removed. The difference is due to the amount of gypsum that can be recycled; the higher cost effectiveness is based on no gypsum recycle and the lower cost effectiveness is based on recycling all the gypsum.

Environmental

The air quality impacts will be below the PSD increments and AAQS. The wet limestone FGD system will reduce SO_2 emissions by about 120,000 TPY per unit. The use of wet limestone FGD to reduce SO_2 emissions has collateral benefits for minimizing emissions of HAPs. An estimated 3,074 TPY of hydrogen chloride (HCL) will be removed, and an estimated 265 TPY of HF will be removed. Based on the use of SCR and the increased oxidization potential of the SCR catalyst, the wet FGD will be a significant component in the removal of mercury from the flue gases.

The use of wet limestone FGD will require about 200,000 TPY of limestone. Water requirements are 564 millions gallons/yr, much of which can be obtained from recycled sources. The wet FGD system will produce about 360,000 TPY per unit of gypsum that can be recycled.

The electrical energy required to run the FGD system and the pressure drop will reduce the available power from FGPP that would otherwise be available to FPL customers. To replace this lost energy, additional emissions from FGPP would occur. The pressure drop is a result of the catalyst modules located in the exhaust gas stream. This pressure drop requires more fan power, which would otherwise be available to the electrical system. Based on the amount of MW-hr required to provide the fan and electric energy, the additional emissions would be 351 TPY. This amount of increased emissions is low compared to the amount of SO_2 reduced.

Energy

Energy penalties occur with wet FGD. With wet FGD, the output is reduced due to the pressure drop of the system as well as the energy requirements of the wet FGD system.

The energy required to operate the FGD equipment would be about 2 percent auxiliary power or about 184,000 MWh per year per unit, while the energy required to overcome the 8 inches of pressure drop requires 35,733 MWh/yr/unit. Taken together, the total energy requirement is 220,000 MWh/yr/unit. This is about 2.4 percent of the gross generation.

Selection of BACT and Rationale

The identification, technical evaluation and ranking and of the available control technologies clearly indicate that wet limestone FGD technology provides the maximum degree of emission reduction for SO_2 emissions from coal fired units. The evaluation of the energy, environmental and economic impacts demonstrate that these controls are cost effective and do not have collateral environmental impacts greater than the benefit of reduction PM. Indeed, there are collateral benefits for the removal of other acid gases and mercury.

Wet limestone FGD technology can achieve the maximum amount of emissions reduction available, and is both technically feasible and demonstrated for FGPP. Wet limestone FGD is feasible and reasonable based on the economic, environmental, and energy impacts. An emission rate of 0.04 lb/MMBtu is proposed as BACT given the evaluations and recent BACT decisions on other similar projects. This proposed emission rate is equal to or less than that established for similar projects as shown in Appendix B, Table B-4.

4.2.5 SULFURIC ACID MIST

Identification of Potentially Applicable Control Technologies

Introduction

The primary issues with gaseous SO_3 emissions are contribution to PM and PM_{10} and contribution to regional haze associated when the SO_3 in the exhaust plumes enters the atmosphere. When exiting in the boiler, SO_3 is difficult to control in standard ESP and fabric filter designs and wet FGD systems especially when using medium-to high-sulfur fuels. While some control is obtained in wet FGD systems, the majority of the SO_3 goes unreacted through the system and is condensed into an aerosol in the FGD system. These aerosols have a particle size within the wavelength of light and are usually exhibited as a blue haze in plumes. These phenomena can also occur in coal-fired units using medium- to high-sulfur coals.

The formation of SO_3 in the combustion process is highly dependent on the boiler operation (e.g., excess O_2). The use of SCR will increase SO_3 emissions. The catalyst increases oxidation of SO_2 to SO_3. When firing petroleum coke, the relatively high vanadium content of the fly ash can build up on boiler surfaces and the SCR catalyst. This can exacerbate the formation of SO_3, and routine cleaning is needed to minimize the effect. With SCR, catalyst design is important in minimizing additional SO_3 emissions.

Boiler Injection Technologies

Boiler injection technologies involve the injection of sorbents within the boiler that react with SO_3 and are subsequently collected in the particulate control device. These technologies include: magnesium hydroxide ($Mg(OH)_2$) slurry injection, dolomitic lime ($Ca(OH)_2$ * $Mg(OH)_2$) injection, limestone injection in the boiler (LIMB), and OmniClear^{TM} injection.

Slurry $Mg(OH)_2$ is a reactive alkali compound that can be used to mitigate SO_3 emissions. The overall chemical reaction can be summarized as follows:

$$Mg(OH)_2 + SO_3 \rightarrow MgSO_4 + H_2O$$

Dolomite ($CaCO_3 * MgCO_3$) is a limestone mineral, an alkaline compound, that can react with and remove SO_3 from the flue gas. The overall chemical reactions can be summarized as:

$$CaCO_3 + SO_3 + H_2O \rightarrow CaSO_4 + H_2O + CO_2$$

$$MgCO_3 + SO_3 + H_2O \rightarrow MgSO_4 + H_2O + CO_2$$

Limestone is an alkaline compound that can react with and remove SO_3 from the flue gas. The overall chemical reaction can be summarized as:

$$CaCO_3 + SO_3 + H_2O \rightarrow CaSO_4 + H_2O + CO_2$$

OmniClear™ products include mixtures of calcium and magnesium compounds, custom blended for particular applications. The OmniClear™ blend for furnace injection in a given application is designed to maximize SO_3 removal efficiency, while minimizing increased particulate loading and removal issues. The overall chemical reactions are similar to:

$$CaCO_3 + SO_3 + H_2O \rightarrow CaSO_4 + H_2O + CO_2$$

$$MgCO_3 + SO_3 + H_2O \rightarrow MgSO_4 + H_2O + CO_2$$

An injection system utilizing pumps is used to inject the sorbent into the furnace where they react with SO_3. Slurry $MgCO_3$ and dolomite injection technology will potentially remove up to 90 percent of the combustion generated SO_3. Limestone and OmniClear™ injection have lower efficiencies. While these technologies will remove SO_3 from the combustion process, they will not significantly reduce the SO_3 downstream of the SCR system.

Injection of SO_3 absorption chemicals is desired upstream of the particulate collection device, which would avoid contamination of the gypsum in the FGD system.

Post-combustion Injection Technologies

The post-combustion injection SAM-control technologies involve injection of reactants downstream of the SCR and air heater and upstream of a PM control device for removal of SO_3. The Project includes the installation of a fabric filter to further control PM, as well as providing assurance for controlling Hg as required by the HAA and the proposed CPR. In addition, the length of ductwork from the air heater to the fabric filters will be relatively long, which allows considerable reaction times. The injection technologies include sodium bicarbonate ($NaHCO_3$) injection, calcium hydroxide – hydrated lime ($Ca(OH)_2$) injection, Trona injection, dry magnesium oxide (MgO) injection, sodium bisulfite ($NaHSO_3$ or SBS) injection, calcium carbonate ($CaCO_3$) injection, micronized limestone injection, and ammonia (NH_3) injection.

Dry sodium bicarbonate is an alkaline compound that can react with and remove SO_3 from the flue gas. Sodium bicarbonate is injected as a dry fine powder and forms a water-soluble particulate. The overall chemical reaction can be summarized as:

$$NaHCO_3 + SO_3 \rightarrow Na2SO_4 + NaHSO_4 + H_2O + CO_2$$

Hydrated lime or calcium hydroxide is a reactive alkaline compound that can be used to mitigate SO_3 emissions. This sorbent is injected as a dry powder with SO removal in the gas stream and the particulate control device. This technology is similar to that used in spray-dryer absorber systems, when combined with the fabric filter for SO_2, and SO_3 control using low-sulfur coals. The overall chemical reaction with the SO_3 can be summarized as:

$$Ca(OH)_2 + SO_3 \rightarrow CaSO_4 + H_2O$$

Trona, or hydrated sodium bicarbonate carbonate, is a reactive alkaline compound that can be used to mitigate SO_3 emissions. The overall chemical reaction involving SO_3 can be summarized as:

$$aNaHCO_3\ Na2CO_3{\cdot}2H_2O + bSO_3 \rightarrow cNaHSO_4 + dNa2SO_4 + eCO_2 + fH_2O$$

$Mg(OH)_3$ is a very reactive alkaline compound that can be used to mitigate SO_3 emissions. The overall chemical reaction can be summarized as:

$$MgO_3 + SO_3 \rightarrow MgSO_4$$

$NaHSO_3$ can react with SO_3 in the flue gas to form sodium sulfate and sodium bisulfate. The overall chemical reaction is:

$$2NaHSO_3 + SO_3 \rightarrow Na2SO_4 + 2SO_2 + H_2O$$

Since commercially available $NaHSO_3$ has up to 10 percent by weight of sodium sulfite, the following side reaction occurs:

$$Na2\ SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

The $NaHSO_3$ generated by the side reaction can react and remove SO_3 in the flue gas. Alternately, it can react directly with SO_3 and remove it as sodium sulfate:

$$Na2SO_3 + SO_3 + O_2 \rightarrow Na2SO_4$$

Micronized dry limestone is an alkaline compound that can provide a large amount of surface area to allow deposition (condensation and adsorption) and removal of the SO_3 on the small limestone particles (large surface area). The adsorption removal mechanism (adsorption of SO_3 on the micronized limestone particles) for SO_3 follows the overall chemical reaction:

$$CaCO_3 + SO_3 + H_2O \rightarrow CaSO_4 + H_2O + CO_2$$

NH_3 injected in the flue gas reacts with SO_3 to form ammonium sulfate and ammonium bisulfate salts. The overall reaction is:

$$aNH_3 + bH2SO_4 \rightarrow c(NH_4)2SO_4 + d(NH_4)HSO_4$$

Ammonia has been used as a control technique of minimizing SO_3 emissions. However, ammonia salts are formed and the downstream particulate control device must be capable of handling the additional particle load. These ammonia salts can affect the quality of the ash as well as find a way into the FGD system. While ammonia slip occurs with SCR systems, some reaction of SO_3 with ammonia slip can form ammonium sulfates. This amount is usually too small to be of benefit. Most often ammonia systems are used only intermittently when needed during certain meteorological conditions that exacerbate opacity problems.

$NaHCO_3$, $NaHSO_3$, and magnesium hydroxide have high reactivities with SO_3 and are predicted to achieve 80- to 90-percent removal of SO_3, if injected prior to a fabric filter. $Ca(OH)_2$ and limestone are not as reactive with SO_3 and would have removal efficiencies of less than 80 percent.

$NaHSO_3$ technology is commercially available, and has been installed in over a dozen units for SO_3 control. An advantage of $NaHSO_3$ injection is that a reaction with SO_2 does not occur, as with other alkaline sorbents (e.g., calcium- or magnesium-based compounds).

Sorbent injection prior to the fabric filters is considered a commercially available and demonstrated technology.

Add-on Controls

The FGD will reduce the SAM emitted. As the SO_3 enters the absorber, some of the SO_3 converts to SAM due to the lowering of the temperature and the moisture in the gases, and reacts with the limestone slurry in the FGD absorber. The actual removal efficiencies vary, but are generally in the range of 53 percent.

WESPs are similar to dry ESPs except that they are well suited for acid mists. They are operated at temperatures less than 190°F. Instead of rapping mechanisms, WESPs typically use water to wash particles from the collectors. The water wash can be either intermittent or continuous. Unlike dry ESPs, resistivity of the particle is not a major factor in performance since the gas stream has high humidity that reduces the resistivity of most particles. Due to this effect, WESPs can collect smaller particles than dry ESPs since resistivity is lowered for all particle sizes and there is less re-entrainment.

WESPs are an available and technically feasible control alternative that can provide the maximum degree of emission reduction for SAM. This technology will also have collateral benefits of removing other fine particulate and aerosols, including mercury. Removal efficiencies of 90 percent can be expected for SAM emissions in new designs, and an emission rate of 0.004 lb/MMBtu is proposed as BACT. This SAM emission level has been approved as BACT on similar recent projects.

Evaluation of Technically Feasible Control Alternatives

Sorbent and WESP systems are available and technically feasible as effective SO_3 control devices for coal fired units. Sorbent injection systems have considerable removal SO_3 range depending upon the application. For FGPP an 80 percent removal is expected. WESP technology is proven to remove acid mists. In addition, there are collateral environmental benefits in that other fine particulate matter and aerosols will be collected. To compare the technologies, the emissions from combustion through control were evaluated. This evaluation used the an approach referred to as the "Southern Company Method" for estimating sulfuric acid mist emissions from coal fired power plants. This method accounts for SO_2 oxidation from the combustion process and in the SCR catalyst as well as

SO_3 scavenging in the air heater, PM control device and wet FGD system. The results are presented in Table 4-10. As shown, the WESP is more effective.

Ranking of Technically Feasible Control Alternatives

WESP will achieve the maximum degree of SAM emission reduction. Sorbent injection systems will not achieve as great an emission reduction with SAM removals in the range of 80 percent. Sorbent injection system, which include dry FGD systems are typically used with very low sulfur coals and would not achieve an emission rate as low as that being proposed for FGPP. In addition, wet FGD systems have additional collateral environmental benefits of achieving removal of other fine particulates and aerosols.

Evaluation of Energy, Environmental and Economic Impacts of Feasible Technologies

Economic

The total estimated capital, annualized, and incremental costs of WESP are based on budgetary cost estimates. The total estimated capital, annualized, and incremental costs are summarized in Table 4-11. The capital cost for one 980-MW unit is $89 million with an annualized cost of $13.2 million. The cost effectiveness based on SAM emission reduction is $7,600 per ton.

Environmental

The environmental benefit of reducing SAM emissions is twofold. First, SAM emissions are visible and can be seen after the water vapor in the plume dissipates. Second, SAM is a fine aerosol that contributes to PM_{10} and particulate matter with aerodynamic size of 2.5 micrograms or less ($PM_{2.5}$) as well as regional haze. In the analysis of regional haze, SAM emissions can contribute 30 percent or more to predicted regional haze.

The addition of WESP will reduce SAM emissions by about 1,750 TPY per unit. The WESP will also reduce other fine particulates and aerosols including HAPs.

The electrical energy required to run the WESP and the pressure drop from the WESP will reduce the available power from FGPP. The pressure drop is a result of WESP located in the exhaust gas stream. The pressure drop to reduce is estimated to 2 inches of water gauge. This pressure drop requires more fan power, which would otherwise be available to the electrical system. Based on the amount of MW-hr required to provide the fan and electric energy, the additional emissions would be 38 TPY. This amount of increased emissions is low compared to the amount of SAM reduced.

Energy

Energy penalties occur with the WESP, since the output is reduced due to the pressure drop and there are energy requirements to operate the system.

The energy required to operate the WESP equipment would be about 14,900 kWh per year per unit while the energy required to overcome the pressure drop requires 8,900 kWh. Taken together, the total energy requirement is about 23,800 kWh. This is about 0.3 percent of the gross generation.

Selection of BACT and Rationale

The proposed technology for reducing SAM emissions is the WESP. This technology can achieve the maximum amount of emission reduction available. WESP technology is technically feasible and demonstrated for FGPP. WESP is feasible and reasonable based on the economic, environmental, and energy impacts. An emission rate of 0.004 lb/MMBtu is proposed as BACT given the evaluations and is equal to or lower than recent BACT decisions on other similar projects as seen in Table B-5, Appendix B.

4.2.6 PRODUCTS OF COMBUSTION—CARBON MONOXIDE AND VOLATILE ORGANIC COMPOUNDS

Carbon Monoxide-Identification of Potentially Applicable Control Technologies

There are no applicable NSPS for the control of carbon monoxide (CO) from utility boilers. CO emissions result from incomplete combustion of the fuel. CO emissions are controlled by boiler design features and combustion air feed rates. The boilers will be designed and operated for high-combustion efficiency, which will inherently minimize the production of CO.

Theoretically, CO emissions can be reduced by passing the flue gas over an oxidation catalyst at a suitable temperature (900 to 1,000°F). In practice, this technology has several unknowns and disadvantages, including the following:

1. No utility pulverized coal-fired boilers are operating with catalytic CO control systems and it would be difficult to locate an oxidation catalyst in the proper temperature zone in a boiler.
2. Catalyst converts up to 70 percent of SO_2 to SO_3.

3. There is a lack of experience with large-scale operation of this technology using particulate-laden gases from coal-fired boilers. Catalysts can be easily eroded and fouled by silica and trace metals in the flue gas.
4. The temperature profile of the flue gas does not match the temperature requirements of typical catalysts.
5. Use of an undemonstrated catalyst technology would reduce the availability and reliability of the plant (e.g., catalyst plugging).
6. The high costs to install and operate the system (additional pressure drop, catalyst replacement, and disposal, etc.) are without corresponding demonstrated need or benefit. Design and operation of the boilers to efficiently combust the fuel will minimize CO emissions. The additional costs to further lower emissions are not justified.

The use of thermal oxidation after the WESP, while also theoretically possible, is not feasible as BACT. Thermal oxidation systems include direct flame incinerators, thermal oxidizers, or afterburners. Afterburners are generally appropriate only to control gases coming from a process where combustion is incomplete and is not appropriate for controlling boiler emissions. Incineration or thermal oxidation is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen, and maintaining it at high temperature for sufficient time to complete combustion to carbon dioxide and water. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process. The auto-ignition temperature of CO is 1,300°F. The use of oxidation catalyst (RCO) can reduce the temperature requirement down to 500°F for CO oxidation.

While regenerative thermal oxidation (RTO) has been demonstrated on a cement kiln in Texas, RTO systems are not considered technically feasible for boilers of the size proposed for FGPP. The proposed boiler will have an estimated stack gas flow rate of over 2 million actual cubic feet per minute (acfm). Thermal oxidation systems are typically designed for flow rates in the range of 500 to 50,000 standard cubic feet per minute (scfm) (EPA Air Pollution Control Fact Sheet – Thermal Oxidation) with custom designed systems for flow rates in the range of 200,000 scfm. CO oxidation is considered technically infeasible for FGPP for the following reasons:

- Never been demonstrated on a coal-fired boiler.

- RTO and RCO would have fuel requirement and natural gas is currently not available at the Site.
- Technical issues include:
  - Heating over 2 million acfm from approximately 130 to 500°F as required with for an RCO and even more so with the requirements of RTO of 1,300°F; and
  - Designing a system of this size with sufficient turbulence and residence time to thermally destruct CO emissions.

Carbon Monoxide-Evaluation and Ranking of Technically Feasible Control Alternatives

BACT emission limits established for coal fired units have required combustion control as the primary method used to control CO emissions. Other technologies such as oxidation catalysts and thermal oxidation are not demonstrated or feasible for coal fired power plants.

Carbon Monoxide-Evaluation of Energy, Environmental and Economic Impacts of Feasible Technologies

Control of CO is inherent to the control of the combustion process. The use of combustion controls such as low-NO_x burners and over-fire air, minimizes the formation of NO_x while also minimizing the emissions of CO through pollution prevention. The resultant combustion efficiency is 99.9 percent for the fuel input. In addition, the environmental impacts of CO are substantially below the significant impact levels and would be immeasurable in the environment.

Carbon Monoxide-Selection of BACT and Rationale

Design of a boiler and combustion air system to efficiently burn the coal represents the technology that will achieve the maximum degree of emission reduction for CO emissions. The CO emission rate for the pulverized coal boiler will achieve an emission rate 0.15 lb/MMBtu limit, which is within the range of BACT emission rates recently established (refer to Table B-6 in Appendix B) and is specific to the type of boiler being considered for FGPP.

Volatile Organic Compounds

Emissions of VOCs also occur during the combustion. Similar to CO, there are no applicable NSPS for VOC emission (non-methane hydrocarbons) from utility boilers. VOC emissions result from incomplete combustion of the fuel. This incomplete combustion can result from poor air/fuel mixing or insufficient oxygen for combustion. Such emissions are reduced by modifying design features of the boiler and control of the combustion air feed rates. Design of a boiler and combustion air system to efficiently burn the coal represents technology that can achieve the maximum degree of emissions reduction as BACT. Similar to CO, oxidation catalyst and thermal oxidation are not feasible to further reduce VOC emissions. The combustion efficiency as related to emissions of VOCs is greater than 99.9 percent. The VOC emission rate proposed for FGPP is 0.0034 lb/MMBtu and is equal to or lower than similar projects (see Appendix B, Table B-6).

4.2.7 FLUORIDES

Fluorides are emitted in the combustion process in gaseous and particulate form as a trace element in fuel. The primary control device for fluorides would be the wet FGD system since fluorides are highly soluble. Fluorides in particulate form are readily removed in the fabric filter. Subsections 4.2.3 and 4.2.4 provide technology descriptions of these technologies. These sections discuss the available technologies for the recommended EPA 5-step process. There are no other control technologies with a greater amount of emissions reduction than the fabric filter followed by the wet FGD system for removal of fluorides. In addition, the addition of the WESP would assure extremely low emissions of fluorides by removing additional fine particulate and aerosols. The latter could contain fluorides since fluorides as soluble. The proposed emission rate of about 2 lb/hr (0.00023 lb/MMBtu/hr) as BACT is in the lower range of recent BACT determinations and is based on 97-percent removal (see Appendix B, Table B-7).

4.2.8 OPACITY

Opacity is a result of particulate matter and/or gases emitted from combustion process. The control equipment that will reduce opacity are the fabric filter, wet FGD system and WESP. The primary particulate control device is the fabric filter where opacity is measured at the outlet. The wet FGD, while designed primarily for SO_2 removal will also reduce PM as well as SAM, both of which contribute to opacity. Finally, the WESP will remove fine particulate and aerosols such as SAM. These fine particulate and aerosols are of a particle size that falls within the wavelength of light and can cause opacity. The combination of the fabric filter, wet FGD and WESP provide the maximum degree of opacity reduction. An opacity standard of 20 percent measured by CEMs after the fabric filter is proposed as BACT. This opacity level is consistent with other similar projects (Appendix B, Table B-3).

4.3 COOLING TOWER

Mechanical draft cooling towers force air through the cooling water to cool the water through evaporative cooling. To minimize water use, the circulating water in the tower is recycled with a portion removed and replaced. The direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water as aerosols in the air stream. The aerosols carried out of the tower are known as "cooling tower drift". These aerosols contain the same chemical characteristics as the water circulating through the cooling tower. As the aerosols leave the cooling tower further evaporation of the aerosol occurs. PM can be formed depending upon the amount of evaporation and original size of the aerosol. The amount of evaporation depends upon meteorological conditions. The PM is made up of the dissolved solids in the circulating water. Cooling towers are used of all types of power plants involving steam generating. This includes natural gas fired combined cycle plants and coal fired power plants.

4.3.1 IDENTIFICATION OF POTENTIALLY APPLICABLE CONTROL TECHNOLOGIES

Drift eliminators are the primary option for addressing drift from cooling towers. Drift eliminators are incorporated into the tower design to remove aerosols from the air stream before exiting the tower. The drift eliminators rely on the inertial separation caused by directional changes in the airflow that occur while passing through the eliminators.

Drift eliminator configurations include cellular (or honeycomb), wave-form, and herringbone (blade-type) designs. Drift eliminators may include various materials such as wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles; ceramic; fiberglass; metal; and plastic.

4.3.2 EVALUATION AND RANKING OF TECHNICAL FEASIBILITY OF CONTROL TECHNOLOGIES

Drift eliminators are the only feasible technology to reduce particulate emissions from mechanical draft cooling towers. Other particulate control device such as ESPs, fabric filters, and WESP are not feasible. Each mechanical draft cooling tower associated with FGPP will have an air flow rate of about 45 million acfm. This amount of air flow is 20 times the flow rate from each ultra-supercritical unit. The only feasible way to limit PM emissions from the mechanical draft cooling towers is the installation of high efficiency drift eliminators within each cooling tower cell.

4.3.3 EVALUATION OF ENERGY, ENVIRONMENTAL AND ECONOMIC IMPACTS OF FEASIBLE TECHNOLOGIES

Drift eliminators as passive control devices. These devices increase the pressure drop through the tower which will increase power requirements. However, the amount of pressure drop is small compared to the pressure drop through the cooling tower fill where the recirculating cooling water is distributed. The mechanical fans are designed to overcome the pressure drop of the drift eliminators. For an environmental perspective, the majority of particulate matter emitted from the cooling tower is typically large particles and much larger than 10 microns. These larger particles settle out near the cooling tower. In contrast, the amount of PM_{10} is generally much smaller. For the mechanical draft cooling towers associated with FGPP the amount of PM_{10} formed is about 16 times less than the total drift.

4.3.4 SELECTION OF BACT FOR COOLING TOWERS

The analysis demonstrates that for the cooling tower the installation of drift eliminators is BACT. Particulate emissions from each combined cycle unit's cooling tower will be controlled utilizing high-efficiency drift eliminators achieving a design drift rate of 0.0005 percent of the cooling tower recirculating water flow. This design drift rate has been established by FDEP as BACT on recent projects including the FPL Turkey Point Unit 5 and FPL West County Energy Center.

4.4 MATERIAL HANDLING

Fugitive particulate emissions from fuel, ash and FGD by-product handling, conveying, and storage will be minimized by equipment design and operating procedures. Fuel will be unloaded into an underground hopper that is protected from wind. Dust from fuel unloading operations will be controlled using dust collection and/or suppression systems.

Conveyors used for transfer of the fuel to the active storage piles will be enclosed for minimizing wind-borne fugitive dust. Unloading onto the active and inactive storage piles will be accomplished using telescoping chutes to minimize dust emissions. The fuel will be reclaimed and conveyed to an enclosed crusher tower. After crushing, the fuel is then conveyed through an enclosed tripper house to the storage silos adjacent to the boilers. All fuel storage silos are connected to a dust collection system. Outdoor conveyors will be enclosed (i.e., covers and windskirts) to minimize dust emissions. All conveyor transfer points will have a dust collection system. The inactive storage pile will be compacted when built and sprayed with a crusting agent and/or chemical stabilizer to prevent wind erosion.

Fugitive particulate emissions from the limestone handling and storage systems will be minimized by equipment design and operating procedures. Limestone will be delivered by rail and unloaded in an enclosed bottom dump building. From the unloading building, limestone will be transferred to an active roof-covered storage area. Conveyors will be covered to minimize dust emissions. Dust collection or suppression techniques will be utilized to minimize dust emissions.

Bottom ash will be collected in a wet bottom ash hopper and have sufficient moisture content to minimize fugitive dust for transport to the by-product storage area or transported offsite for use as an aggregate. Fly ash from the ESPs or fabric filters will be pneumatically conveyed to storage silos that will be equipped with fabric filters to minimize PM emissions. Fly ash, used for cement or other purposes, will be transported offsite in enclosed tanker trucks or rail cars. While filling these trucks or rail cars, displaced air will be vented to the dust collection system. Fly ash stored in the by-product storage area will be mixed with water (e.g., pug mill), unloaded into covered trucks, and transported to the onsite by-product disposal area.

Fugitive emissions from the FGD byproduct storage area are minimized by the higher moisture content of the by-products. The FGD by-product is calcium sulfate (gypsum) with inherently high moisture content. Saleable gypsum will be transported offsite in trucks or railcars. Onsite disposal of gypsum will be by trucks from the gypsum storage to the byproduct storage area.

Watering, using a water-spray truck, will also be performed as necessary to minimize fugitive emissions from active areas (i.e., unpaved roads and working areas of the storage area).

4.5 AUXILIARY BOILER

The proposed BACT for the auxiliary boiler is the use of distillate oil to limit emissions of PM and SO_2, and good combustion practices to limit emissions of NO_x, CO, and VOC. Distillate oil with sulfur content of 0.0015 percent is the cleanest available fossil fuels for this purpose and will minimize the emissions of PM and SO_2 to emission levels recognized as BACT. The auxiliary boiler will limit emissions using low-NO_x burners to an emission level of 0.12 lb/MMBtu. The emission of CO will also be minimized through the use of good combustion practices to meet the requirements of 40 CFR Subpart DDDDD.

The use of alternate controls such as SCR or SNCR is neither cost effective nor practicable. The auxiliary boiler will only be used for startup of the main units and will be limited to a capacity factor of 10 percent or an equivalent of 876 hours per year at full load. Alternative controls would not be cost effective and the installation of additional control equipment unnecessary.

4.6 EMERGENCY GENERATORS AND DIESEL FIRE PUMP

The emergency generators proposed for FGPP will utilize clean fuel (i.e., 0.0015-percent sulfur distillate oil) and good combustion techniques to minimize emissions. These engines will be purchased from manufacturers that will meet the EPA non-road emission standards, specifically 40 CFR, Subpart IIII. EPA has established emission standards for CO, VOCs, PM and NO_x for classes of engines and has established dates for compliance. The engines purchased for FGPP will meet the EPA non-road emission standards at the time of purchase. These emission rates are proposed as BACT (see Table 2-6). Each will have potential emissions for each regulated pollutant of less than 5 TPY. As a result, the fire pump engine is classified as an insignificant activity under FDEP Rule 62-213.430(6)(b), F.A.C.

TABLE 4-1
PROPOSED BACT EMISSION RATES AND COMPLIANCE METHODS FOR FGPP

Pollutant	Emission Unit	Proposed Emission Limits	Compliance Methods
PM/PM$_{10}$	Boilers	0.013 lb/MMBtu	Initial/Annual: EPA Method 5B
		20% Opacity	40 CFR Part 75 COMS after Fabric Filter
	Cooling Tower	0.0005% drift of circulating water rate	Manufacturer certification of design drift rate
	Material Handling	0.01 grain/cubic foot for fabric filters	Manufacturer certification of filter design
		Fugitive-best management practices	Design and controls (e.g., watering) as required
	Auxiliary Boiler	0.0015% Sulfur Distillate Oil	10% or less VE using EPA Method 9
	Emergency Generators	EPA Tier 2 Emission Standards	Manufacturer certification of engine selected
	Fire Pump	EPA Tier 3 Emission Standards	Manufacturer certification of engine selected
NO$_x$	Boilers	0.05 lb/MMBtu	40 CFR Part 75 CEMS; 30-day rolling average
	Auxiliary Boiler	0.12 lb/MMBtu	EPA Method 7e; Initial and Annual
	Emergency Generators	EPA Tier 2 Emission Standards	Manufacturer certification of engine selected
	Fire Pump	EPA Tier 3 Emission Standards	Manufacturer certification of engine selected
SO$_2$	Boilers	0.04 lb/MMBtu	40 CFR Part 75 CEMS; 30-day rolling average
	Auxiliary Boiler	0.0015% Sulfur Distillate Oil	Vendor supplied data
	Emergency Generators	0.0015% Sulfur Distillate Oil	Vendor supplied data
	Fire Pump	0.0015% Sulfur Distillate Oil	Vendor supplied data
CO	Boilers	0.15 lb/MMBtu	Initial/Annual: EPA Method 10
	Auxiliary Boiler	0.08 lb/MMBtu	EPA Method 10; Initial Only
	Emergency Generators	EPA Tier 2 Emission Standards	Manufacturer certification of engine selected
	Fire Pump	EPA Tier 3 Emission Standards	Manufacturer certification of engine selected
VOC	Boilers	0.0034 lb/MMBtu	Initial Only: EPA Methods 18 or 25A (baseload)
	Auxiliary Boiler	Good combustion	Meet CO emission limits
	Emergency Generators	EPA Tier 2 Emission Standards	Manufacturer certification of engine selected
	Fire Pump	EPA Tier 3 Emission Standards	Manufacturer certification of engine selected
SAM	Boilers	0.004 lb/MMBtu	Initial/Annual: Method 8A Controlled Condensate
	Auxiliary Boiler	0.0015% Sulfur Distillate Oil	Vendor supplied data
	Emergency Generators	0.0015% Sulfur Distillate Oil	Vendor supplied data
	Fire Pump	0.0015% Sulfur Distillate Oil	Vendor supplied data
Fluorides	Boilers	0.00023 lb/MMBtu	Initial: EPA Method 26A[1]; Continuous: Meeting SO$_2$ emission limit
Mercury	Boilers	9.9 x 10^{-6} lb/MW-hr	40 CFR Part 60; Appendix B P.S. 12A; CEMS annual average

Note: BACT = Best Available Control Technology.
CEMS = Continuous Emission Monitoring System.
COMS = Continuous Opacity Monitoring System.
PSD = Prevention of Significant Deterioration.

[1] EPA (2006) reports precision and accuracy difficulties below 5 ppm. Emission level is about 0.3 ppm and testing uncertainties may occur.

TABLE 4-2

SUMMARY OF ENVIRONMENTAL AND ENERGY IMPACTS FOR FGPP (PER 980-MW UNIT)

PCE/Category	Benefit/Cost	Value	Units
SCR			
Cost Effectiveness	$ per tons NO_x Removed	853	$/ton
Environmental	NO_x removed	11,432	tons/year
	Ammonia Use	4,084	tons/year
	Ammonia Slip	38	tons/year
	Lost Generation from Pressure Drop	78	tons/year
Energy	Pressure Drop	35,733	MW-hr
	Electrical Energy	12,877	MW-hr
	Supplementary Heat	9,000	MMBtu
ESP			
Cost Effectiveness	$ per tons PM Removed	39	$/ton with ash sale
	$ per tons PM Removed	52	$/ton with ash disposal
Environmental	PM Removed	257,978	tons/yr
	Metals-HAPs	3.14	tons/yr removed
	Lost Generation from Pressure Drop	24	tons/year
Energy	Pressure Drop	included	MW-hr
	Electrical Energy	15,119	MW-hr
Baghouse			
Cost Effectiveness	$ per tons PM Removed	43	$/ton with ash sale
	$ per tons PM Removed	55	$/ton with ash disposal
Environmental	PM Removed	257,482	tons/yr
	Metals-HAPs	3.14	tons/yr removed
	Lost Generation from Pressure Drop	57	tons/year
Energy	Pressure Drop	35,733	MW-hr
	Electrical Energy	included	MW-hr
Wet Limestone FGD			
Cost Effectiveness	$ per tons SO_2 Removed	275	$/ton with gypsum sale
	$ per tons SO_2 Removed	319	$/ton without gypsum sale
Environmental	SO_2 Removed	121,177	tons/yr
	HCL removed	3,074.33	tons/yr removed
	HF removed	265.65	tons/yr removed
	Limestone Used	202,624	tons/yr
	Water Usage	564,232	1,000 gallons
	Lost Generation from Pressure Drop	351	tons/year
Energy	Pressure Drop	35,733	MW-hr
	Electrical Energy	183,960	MW-hr
Wet ESP			
Cost Effectiveness	$ per tons SAM Removed	7,557	$/ton
Environmental	SAM removed	1,753	tons/yr
	Water Use	183,960	1,000 gallons
	Lost Generation from Pressure Drop	38	tons/year
Energy	Pressure Drop	8,875	MW-hr
	Electrical Energy	14,892	MW-hr

TABLE 4-3
FGPP COST EFFECTIVENESS OF SCR, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR

Cost Items	Cost Factors[a]	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
SCR Equipment and Materials	FPL Cost Estimate, Materials	19,396,352
Emission Monitoring	5% of SCR equipment cost	969,818
Ammonia Storage System	Vendor quote[b], 10,000 gallon storage tank	170,000
Installation:		
Foundation and Structure Support	FPL Cost Estimate	12,078,724
Control Room and Enclosures	4% of equipment cost, engineering estimate	775,854
Transition Ducts to and from SCR	FPL Cost Estimate, included in foundation and structure costs	included
Wiring and Conduit	FPL Cost Estimate, included in foundation and structure costs	included
Insulation	FPL Cost Estimate, included in foundation and structure costs	included
Motor Control and Motor Starters	FPL Cost Estimate, included in foundation and structure costs	included
SCR Bypass Duct	FPL Cost Estimate, included in foundation and structure costs	included
Induced Draft Fan	FPL Cost Estimate, included in foundation and structure costs	included
Taxes	Not Required for Pollution Control Equipment	0
Total DCC:		33,390,748
INDIRECT CAPITAL COSTS (ICC):		
General Facilities	FPL Cost Estimate, included in engineering and construction fees	included
Engineering and Construction Fees	FPL Cost Estimate	9,442,523
Performance test	1% of DCC	333,907
Process Contingencies	FPL Cost Estimate, included in engineering and construction fees	0
Total ICC:		9,776,430
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + Project Contingencies	43,167,179
DIRECT OPERATING COSTS (DOC):		
Operating Labor		
Operator	1/2 additional operator @ $65,000/year	65,000
Supervisor	20% of operating labor cost	13,000
Maintenance	Materials	400,000
Maintenance Labor	66.7% of Maintenance Materials	267,000
SCR Energy Requirement	8 inch pressure drop, $30/MWh	1,072,000
Auxiliary Power Cost	0.14% auxiliary power, $30/MWh	386,316
Ammonia Cost	$435/ton, 812 lb/hr at full load	1,735,687
Supplementary Heat	$3/Mbtu - 650 Btu/lb NH3 vaporization + 600 Btu/lb for air heating	27,000
Catalyst Replacement and disposal	$5,125,000 with 3-5 year life	1,708,333
Total DOC:		5,674,336
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	4,074,982
ANNUALIZED COSTS (AC):	DOC + CRC	9,749,318
BASELINE NO_x EMISSIONS (TPY) :	0.35 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr 100% Capacity Factor	13,337
MAXIMUM NO_x EMISSIONS (TPY) :	0.05 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr	1,905
REDUCTION IN NO_x EMISSONS (TPY):		11,432
COST EFFECTIVENESS:	$ per ton of NO_x Removed	853

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

[b] Ammonia storage tank vendor's quotation for RM Technologies, for a 10,000-gallon anhydrous ammonia tank. Includes stainless steel horizontal tank, valves, and transfer station.

TABLE 4-4

FGPP COST EFFECTIVENESS OF DRY ESP FOR PM CONTROL, ONE 980 MW UNIT, 100-PERCENT CAPACITY FACTOR, FLY ASH RECYCLED

Cost Items	Cost Factors*	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)	Based on EPA Air Pollution Control Fact Sheet EPA-452/F-03-028	58,766,813
ESP	Included in Equipment and Materials	included
Ductwork to ESP inlet and oulet	Included in Equipment and Materials	included
Electrical switchgear, motor control centers	Included in Equipment and Materials	included
Instruments and Controls	Included in Equipment and Materials	included
Freight	Included in Equipment and Materials	included
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		58,766,813
Direct Installation Costs		
Foundation and Structure Support	Included in Equipment and Materials	included
Handling & Erection	Included in Equipment and Materials	included
Electrical	Included in Equipment and Materials	included
Piping	Included in Equipment and Materials	included
Insulation for ductwork	Included in Equipment and Materials	included
Painting	Included in Equipment and Materials	included
Total Direct Installation Costs		
Total DCC:		58,766,813
INDIRECT CAPITAL COSTS (ICC):		
Contractor Fees +	10% of PEC	5,876,681
Performance test +	1% of PEC	587,668
Contingencies	3% of PEC	1,763,004
Total ICC:		8,227,354
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	66,994,167
DIRECT OPERATING COSTS (DOC):		
Operator	1/2 additional operator @ 65,000/year	33,000
Supervisor	20% of operating labor cost	6,600
Fan Power Requirement	2 inch pressure drop, $30/MW-hr	293,029
TR Set Energy Use	Est. Plate Area = 307,400 ft^2, $30/MW-hr	156,724
Maintenance Materials	Eng. Estimate	150,000
Maintenance Labor	66.7% of Maintenance materials	100,050
Ash Disposal	Ash recycled	0
Total DOC:		739,403
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	273,812
Property Taxes	1% of total capital investment	669,942
Insurance	1% of total capital investment	669,942
Administration	2% of total capital investment	1,339,883
Total IOC:		2,953,578
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	6,324,249
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	10,017,230
BASELINE PM EMISSIONS (TPY):	6.77 lb/MMBtu, 8,700 MMBtu/hr, 8,760 hr/yr	257,978
MAXIMUM PM EMISSIONS (TPY):	0.013 lb/MMBtu, 8,700 MMBtu/hr, 8760 hr/yr	421
REDUCTION IN PM EMISSIONS (TPY):		257,556
COST EFFECTIVENESS:	$ per ton of PM Removed	39

* Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

TABLE 4-5
FGPP COST EFFECTIVENESS OF DRY ESP FOR PM CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR, ASH STORED ONSITE

Cost Items	Cost Factors[a]	Cost ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)	Based on EPA Air Pollution Control Fact Sheet EPA-452/ F-03-028	58,766,813
ESP	Included in Equipment and Materials	included
Ductwork to ESP inlet and oulet	Included in Equipment and Materials	included
Electrical switchgear, motor control centers	Included in Equipment and Materials	included
Instruments and Controls	Included in Equipment and Materials	included
Freight	Included in Equipment and Materials	included
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		58,766,813
Direct Installation Costs		
Foundation and Structure Support	Included in Equipment and Materials	included
Handling & Erection	Included in Equipment and Materials	included
Electrical	Included in Equipment and Materials	included
Piping	Included in Equipment and Materials	included
Insulation for ductwork	Included in Equipment and Materials	included
Painting	Included in Equipment and Materials	included
Total Direct Installation Costs		
Total DCC:		58,766,813
INDIRECT CAPITAL COSTS (ICC):		
Contractor Fees +	10% of PEC	5,876,681
Performance test +	1% of PEC	587,668
Contingencies	3% of PEC	1,763,004
Total ICC:		8,227,354
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	66,994,167
DIRECT OPERATING COSTS (DOC):		
Operator	1/2 additional operator @ 65,000/year	33,000
Supervisor	20% of operating labor cost	6,600
Fan Power Requirement	2 inch pressure drop, $0.06/kwH	586,058
TR Sets	Est. Plate Area = 307,400 ft^2, $30/MW-hr	156,724
Maintenance Materials	Eng. Estimate = labor cost	150,000
Maintenance Labor	66.7% of Maintenance materials	100,050
Ash Disposal	Ash stored onsite	2,991,390
Total DOC:		4,023,822
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	449,629
Property Taxes	1% of total capital investment	669,942
Insurance	1% of total capital investment	669,942
Administration	2% of total capital investment	1,339,883
Total IOC:		3,129,396
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	6,324,249
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	13,477,467
BASELINE PM EMISSIONS (TPY):	6.77 lb/MMBtu, 8,700 MMBtu/hr, 8,760 hr/yr	257,978
MAXIMUM PM EMISSIONS (TPY):	0.013 lb/MMBtu, 8,700 MMBtu/hr, 8760 hr/yr	495
REDUCTION IN PM EMISSIONS (TPY):		257,482
COST EFFECTIVENESS:	$ per ton of PM Removed	52

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

TABLE 4-6
FGPP COST EFFECTIVENESS OF BAGHOUSE FOR PM CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR, FLY ASH RECYCLED

Cost Items	Cost Factors[a]	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)	Materials and Equipment, FPL Cost Estimate	22,208,898
Baghouse.	FPL Cost Estimate, included in Equipment and Materials	included
Ductwork to Baghouse inlet and oulet	FPL Cost Estimate, included in Equipment and Materials	included
Electrical switchgear, motor control centers	FPL Cost Estimate, included in Equipment and Materials	included
Instruments and Controls	FPL Cost Estimate, included in Equipment and Materials	included
Freight	FPL Cost Estimate, included in Equipment and Materials	included
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		22,208,898
Direct Installation Costs	FPL Cost Estimate	26,668,127
Foundation and Structure Support	FPL Cost Estimate, included in Installation Costs	included
Handling & Erection	FPL Cost Estimate, included in Installation Costs	included
Electrical	FPL Cost Estimate, included in Installation Costs	included
Piping	FPL Cost Estimate, included in Installation Costs	included
Insulation for ductwork	FPL Cost Estimate, included in Installation Costs	included
Painting	FPL Cost Estimate, included in Installation Costs	included
Total Direct Installation Costs		26,668,127
Total DCC:		48,877,024
INDIRECT CAPITAL COSTS (ICC):	FPL Cost Estimate	14,663,107
Engineering	FPL Cost Estimate, included in Indirect Capital Costs	
Contractor Fees	FPL Cost Estimate, included in Indirect Capital Costs	2,220,890
Performance test +	1% of PEC	222,089
Contingencies	3% of PEC	666,267
Total ICC:		17,772,353
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	66,649,377
DIRECT OPERATING COSTS (DOC):		
Operator	1/2 additional operator @ 65,000/year	33,000
Supervisor	20% of operating labor cost	6,600
Electricity	8 inch pressure drop, $30/MWh	1,072,000
Bag Replacement	Bags and Cages Replacement	872,000
Maintenance Materials	Materials	132,000
Maintenance Labor	66.7% of Maintenance materials	88,000
Ash Disposal	Ash recycled	0
Total DOC:		2,203,600
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	23,760
Property Taxes	1% of total capital investment	666,494
Insurance	1% of total capital investment	666,494
Administration	2% of total capital investment	1,332,988
Total IOC:		2,689,735
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	6,291,701
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	11,185,036
BASELINE PM EMISSIONS (TPY) :	6.77 lb/MMBtu, 8,700 MMBtu/hr, 8,760 hr/yr	257,978
MAXIMUM PM EMISSIONS (TPY) :	0.013 lb/MMBtu, 8,700 MMBtu/hr, 8760 hr/yr	495
REDUCTION IN PM EMISSIONS (TPY):		257,482
COST EFFECTIVENESS:	$ per ton of PM Removed	43

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[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

TABLE 4-7
FGPP COST EFFECTIVENESS OF BAGHOUSE FOR PM CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR, FLY ASH STORED ONSITE

Cost Items	Cost Factors[a]	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)	Materials and Equipment, FPL Cost Estimate	22,208,898
Baghouse.	FPL Cost Estimate, included in Equipment and Materials	included
Ductwork to Baghouse inlet and oulet	FPL Cost Estimate, included in Equipment and Materials	included
Electrical switchgear, motor control centers	FPL Cost Estimate, included in Equipment and Materials	included
Instruments and Controls	FPL Cost Estimate, included in Equipment and Materials	included
Freight	FPL Cost Estimate, included in Equipment and Materials	included
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		22,208,898
Direct Installation Costs	FPL Cost Estimate	26,668,127
Foundation and Structure Support	FPL Cost Estimate, included in Installation Costs	included
Handling & Erection	FPL Cost Estimate, included in Installation Costs	included
Electrical	FPL Cost Estimate, included in Installation Costs	included
Piping	FPL Cost Estimate, included in Installation Costs	included
Insulation for ductwork	FPL Cost Estimate, included in Installation Costs	included
Painting	FPL Cost Estimate, included in Installation Costs	included
Total Direct Installation Costs		26,668,127
Total DCC:		48,877,024
INDIRECT CAPITAL COSTS (ICC):	FPL Cost Estimate	14,663,107
Engineering	FPL Cost Estimate, included in Indirect Capital Costs	
Contractor Fees	FPL Cost Estimate, included in Indirect Capital Costs	2,220,890
Performance test +	1% of PEC	222,089
Contingencies	3% of PEC	666,267
Total ICC:		17,772,353
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	66,649,377
DIRECT OPERATING COSTS (DOC):		
Operator	1/2 additional operator @ 65,000/year	33,000
Supervisor	20% of operating labor cost	6,600
Electricity	8 inch pressure drop, $30/MWh	1,072,000
Bag Replacement	Bags and Cages Replacement	872,000
Maintenance Materials	Materials	132,000
Maintenance Labor	66.7% of Maintenance materials	88,000
Ash Disposal	Ash stored in byproduct storage	2,991,390
Total DOC:		5,194,990
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	23,760
Property Taxes	1% of total capital investment	666,494
Insurance	1% of total capital investment	666,494
Administration	2% of total capital investment	1,332,988
Total IOC:		2,689,735
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	6,291,701
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	14,176,426
BASELINE PM EMISSIONS (TPY):	6.77 lb/MMBtu, 8,700 MMBtu/hr, 8,760 hr/yr	257,977.6
MAXIMUM PM EMISSIONS (TPY):	0.013 lb/MMBtu, 8,700 MMBtu/hr, 8760 hr/yr	495.4
REDUCTION IN PM EMISSIONS (TPY):		257,482.2
COST EFFECTIVENESS:	$ per ton of PM Removed	55

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 3, Sixth edition.

TABLE 4-8

FGPP COST EFFECTIVENESS OF WET LIMESTONE FGD FOR SO_2 CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR, BYPRODUCT RECYCLE

Cost Items	Cost Factors[a]	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Materials and Equipment	FPL Cost Estimate, included in Equipment and Materials	54,140,118
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		54,140,118
Direct Installation	FPL Cost Estimate	57,339,806
Total Direct Installation:		57,339,806
Total DCC (PEC + Direct Installation):		111,479,924
INDIRECT CAPITAL COSTS (ICC):	FPL Cost Estimate	33,443,977
Engineering	FPL Cost Estimate, included in Indirect Capital Costs	included
Construction and field expenses	FPL Cost Estimate, included in Indirect Capital Costs	included
Contractor Fees	2% of PEC (for excluded items)	included
Startup	1% of PEC	541,401
Performance test	1% of PEC	541,401
Contingencies	10% of PEC	included
Total ICC:		34,526,779
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	146,006,703
DIRECT OPERATING COSTS (DOC):		
Operating Labor		
Operator	12 operators @ 65,000/year	780,000
Supervisor	20% of operator labor cost	156,000
Maintenance		
Materials	Maintenance Materials	1,030,000
Labor	66.7% of maintenance materials cost	687,000
Operating Materials		
Reagent	$12/ton, 1.03 Stoich. 95.5% $CaCO_3$	2,431,488
Water	1,073 gpm, $0.08/1000 gal	451,385
Electricity	2% auxiliary power, $30/MWh	5,518,800
Pressure Drop	8 inch pressure drop, $30/MWh	1,072,000
Dry Waste Disposal	Gypsum Recycled	0
Total DOC:		12,126,673
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	1,591,800
Property Taxes	1% of total capital investment	1,460,067
Insurance	1% of total capital investment	1,460,067
Administration	2% of total capital investment	2,920,134
Total IOC:		7,432,068
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	13,783,033
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	33,341,774
BASELINE EMISSIONS (TPY) :	3.22 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr	122,701
MAXIMUM EMISSIONS (TPY) :	0.04 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr	1,524
REDUCTION IN SO_2 EMISSIONS (TPY):		121,177
INCREMENTAL COST EFFECTIVENESS:	$ per ton of pollutants Removed	275

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 5, Sixth edition.

TABLE 4-9

FGPP COST EFFECTIVENESS OF WET LIMESTONE FGD FOR SO_2 CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR, WITH BYPRODUCT STORAGE

Cost Items	Cost Factors[a]	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Materials and Equipment	FPL Cost Estimate, included in Equipment and Materials	54,140,118
Taxes	Not required for Pollution Control Equipment	included
Total PEC:		54,140,118
Direct Installation	FPL Cost Estimate	57,339,806
Total Direct Installation:		57,339,806
Total DCC (PEC + Direct Installation):		111,479,924
INDIRECT CAPITAL COSTS (ICC):	FPL Cost Estimate	33,443,977
Engineering	FPL Cost Estimate, included in Indirect Capital Costs	included
Construction and field expenses	FPL Cost Estimate, included in Indirect Capital Costs	included
Contractor Fees	2% of PEC (for excluded items)	included
Startup	1% of PEC	541,401
Performance test	1% of PEC	541,401
Contingencies	10% of PEC	included
Total ICC:		34,526,779
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	146,006,703
DIRECT OPERATING COSTS (DOC):		
Operating Labor		
Operator	12 operators @ 65,000/year (Sargent & Lundy, 2005)	780,000
Supervisor	20% of operator labor cost	156,000
Maintenance		
Materials	Maintenance Materials	1,030,000
Labor	66.7% of maintenance materials cost	687,000
Operating Materials		
Reagent	$12/ton, 1.03 Stoich. 95.5% $CaCO_3$	2,431,488
Water	1,073 gpm, $0.08/1000 gal	451,385
Electricity	2% auxiliary power, $30/MWh	5,518,800
Pressure Drop	8 inch pressure drop, $30/MWh	1,072,000
Dry Waste Disposal	15$ per ton, 10 percent moisture	5,335,470
Total DOC:		17,462,143
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	1,591,800
Property Taxes	1% of total capital investment	1,460,067
Insurance	1% of total capital investment	1,460,067
Administration	2% of total capital investment	2,920,134
Total IOC:		7,432,068
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	13,783,033
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	38,677,244
BASELINE EMISSIONS (TPY):	3.22 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr	122,701
MAXIMUM EMISSIONS (TPY):	0.04 lb/MMBtu, 8700 MMBtu/hr, 8760 hr/yr	1,524
REDUCTION IN SO_2 EMISSIONS (TPY):		121,177
INCREMENTAL COST EFFECTIVENESS:	$ per ton of pollutants Removed	319

[a] Unless otherwise specified, factors and cost estimates reflect OAQPS Cost Manual, Section 5, Sixth edition.

TABLE 4-10

SULFURIC ACID MIST (SAM) EMISSIONS FOR FPL GLADES POWER PARK

Category	Units	SBS Injection	Wet-ESP
Coal Sulfur Content	%	1.98	1.98
Coal Heat Content	Btu/lb	12,324	12,324
Uncontrolled SO_2 Emissions[a]	lb/MMBtu	3.21	3.21
Combustion Factor[b]		0.011	0.011
SAM from Combustion	lb/MMBtu	0.054	0.054
SCR Factor[c]		0.017	0.017
SAM produced by SCR	lb/MMBtu	0.083	0.083
SAM Leaving SCR[d]	lb/MMBtu	0.137	0.137
Air Heater Factor[e]		0.850	0.850
SAM Leaving Air Heater	lb/MMBtu	0.116	0.116
SBS Injection and Baghouse Factor[f]		0.200	0.770
SAM Leaving Baghouse	lb/MMBtu	0.023	0.090
FGD System Factor[g]		0.470	0.470
SAM Leaving FGD	lb/MMBtu	**0.011**	0.042
Wet-ESP Removal		NA	0.100
SAM Leaving Wet-ESP	lb/MMBtu	NA	**0.004**

[a] Assumes 100 percent of sulfur converted to SO_2 for the purpose of calculating the amount of SAM produced; actual SO_2 emissions are 95 percent.

[b] Table 5-1 Souther Company, (2005); 0.011 for high sulfur eastern bituminous coal.

[c] 1.7 percent SO_3 produced from SO_2 oxidation.

[d] Section 4 Southern Comapny; 0.6 ppm ammonia slip scavenging SAM.

[e] Table 4-1 Southern Conapny (2005); 0.85 for high/medium sulfur eastern bituminous.

[f] 0.2 for 80-percent removal with SBS injection; 0.77 for 23 percent removal estimated without injection.

[g] 0.47 Table 4-3 Southern Company (2005); representative of 53 percent removal in wet FDG system.

[h] 0.1 for 90-percent removal with WESP.

TABLE 4-11

FGPP COST EFFECTIVENESS OF WET ELECTROSTATIC PRECIPITATOR FOR SAM CONTROL, ONE 980-MW UNIT, 100-PERCENT CAPACITY FACTOR

Cost Items	Cost Factors*	Cost 2005 ($)
DIRECT CAPITAL COSTS (DCC):		
Purchased Equipment Cost (PEC)		
Wet ESP Equipment and Materials	FPL Cost Estimate	35.375.623
Pumps, piping and valves. external to ESP	FPL Cost Estimate. included in Equipment and Materials	included
Water handling/treatment facilities (Design and equipment cost: containment. skimming. sludge removal. clarification. pH adj. recirculation)	FPL Cost Estimate. included in Equipment and Materials	included
Ductwork to ESP inlet and oulet	FPL Cost Estimate. included in Equipment and Materials	included
Electrical switchgear. motor control centers	FPL Cost Estimate. included in Equipment and Materials	included
Instruments and Controls	FPL Cost Estimate. included in Equipment and Materials	included
Freight	FPL Cost Estimate. included in Equipment and Materials	included
Taxes	Not requirted for Pollution Control Equipment	included
Total PEC:		35.375.623
Direct Installation Costs	FPL Cost Estimate	24.792.022
Foundation and Structure Support	FPL Cost Estimate. included in Installtaion Costs	included
Handling & Erection	FPL Cost Estimate. included in Installtaion Costs	included
Electrical	FPL Cost Estimate. included in Installtaion Costs	included
Piping	FPL Cost Estimate. included in Installtaion Costs	included
Insulation for ductwork	FPL Cost Estimate. included in Installtaion Costs	included
Painting	FPL Cost Estimate. included in Installtaion Costs	included
Total Direct Installation Costs		
Total DCC:		35.375.623
INDIRECT CAPITAL COSTS (ICC):	FPL Cost Estimate	18.050.294
Engineering	FPL Cost Estimate. included in Indirect Capital Costs	included
Contractor Fees +	FPL Cost Estimate. included in Indirect Capital Costs	included
Performance test +	1% of PEC	353.756
Contingencies	FPL Cost Estimate. included in Indirect Capital Costs	included
Total ICC:		18.404.050
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	89.155.296
DIRECT OPERATING COSTS (DOC):		
Operating Labor		
Operator	1/2 additional operator @ 65.000/year	33.000
Supervisor	20% of operating lablor cost	6.600
Maintenance Materials	Engineering Estimate	150.000
Maintenance Labor	66.7% of Maintenance Materials	100.000
Water/Treatment	350 GPM for 8760 hr/yr; $0.8/1000gal	147.168
Auxiliary Power Cost	2 inch pressure drop + 0.2% of net generation. $30/MWh	713.000
Total DOC:		1.149.768
INDIRECT OPERATING COSTS (IOC):		
Overhead	60% of oper. labor & maintenance	113.760
Property Taxes	1% of total capital investment	891.553
Insurance	1% of total capital investment	891.553
Administration	2% of total capital investment	1.783.106
Total IOC:		3.679.972
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	8.416.260
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	13.246.000
BASELINE SAM EMISSIONS (TPY) :	0.05 lb/MMBtu. 8.700 MMBtu/hr. 8.760 hr/yr	1.905.3
MAXIMUM SAM EMISSIONS (TPY) :	0.004 lb/MMBtu. 8.700 MMBtu/hr. 8.760 hr/yr	152.4
REDUCTION IN SAM EMISSONS (TPY):		1752.9
COST EFFECTIVENESS:	$ per ton of SAM Removed	7.557

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[a] Unless otherwise specified. factors and cost estimates reflect OAQPS Cost Manual. Section 3. Sixth edition

5.0 AMBIENT MONITORING ANALYSIS

The PSD rules require that an air quality analysis be conducted for each criteria and non-criteria pollutant subject to regulation under the CAA before a major stationary source is constructed. Criteria pollutants are those pollutants for which AAQS have been established. Non-criteria pollutants are those pollutants that may be regulated by emission standards for which AAQS have not been established. This analysis may be performed by the use of modeling and/or by monitoring the air quality. In addition, if EPA has not established an acceptable ambient monitoring method for the pollutant, monitoring is not required.

Based on the potential emissions from FGPP (see Table 3-3), pre-construction ambient monitoring analyses for SO_2, PM_{10}, NO_2, CO, O_3 (based on VOC emissions), and SAM may be required as part of the application. Ambient monitoring analyses are not required if it can be demonstrated that the proposed source's maximum air quality impacts will not exceed the PSD *de minimis* concentration levels and, for O_3 (based on VOC emissions), VOC emissions of 100 TPY.

Although FGPP's emissions are greater than the significant emission rate for fluorides and SAM, EPA has not established an air monitoring method for these pollutants. In addition, there are no AAQS, PSD Increments or other air quality standards for these specific pollutants.

As shown in Section 6.10, FGPP's maximum impacts are predicted to be below the PSD *de minimis* concentration levels for all pollutants.

For O_3, EPA has established a PSD *de minimis* monitoring level for a project based on an increase in VOC emissions of 100 TPY or more, which would require a pre-construction ambient monitoring analysis. Because FGPP's VOC emissions are greater than 100 TPY, pre-construction ambient monitoring analysis for O_3 (based on VOC emissions) is required as part of the application.

Since FGPP's maximum 24-hour average SO_2 and PM_{10} impacts are predicted to be greater than the significant impact levels (see Section 6.10), more detailed analyses are required to address compliance with the AAQS and PSD Class II increments. For the AAQS analyses, total air quality impacts are predicted for the modeled sources, which are added to a non-modeled background concentration. The non-modeled background concentrations are estimated from representative ambient air quality monitoring data obtained from air monitoring stations. The background concentrations developed for FGPP are discussed in the following sections.

5.1 O_3 AMBIENT MONITORING ANALYSIS

Ambient O_3 monitoring data from existing monitoring stations are included in this application to satisfy the pre-construction monitoring requirement. Glades County and adjacent Counties are classified as attainment or maintenance areas for O_3. The nearest monitor to the Site that measures O_3 concentrations is located in Sebring (AIRS No. 12-055-0003) in Highland County, approximately 37 km (22 miles) from the Site. Since O_3 is a regional pollutant, O_3 monitoring data collected in Highlands County are considered to be representative of O_3 concentrations for the region and are used to satisfy this requirement for FGPP. This station is operated by the FDEP and measures concentrations according to EPA procedures.

As shown in Table 5-1, from 2003 through 2005, the second-highest 1-hour average O_3 concentration measured at Sebring was 0.084 ppm. This maximum concentration is less than the existing 1-hour average O_3 AAQS of 0.12 ppm. In addition, the 3-year average of the fourth highest 8-hour average O_3 concentration was 0.072 ppm, and is below the revised 8-hour average O_3 AAQS of 0.08 ppm. These O_3 monitoring data are included as part of this permit application to satisfy the pre-construction monitoring requirement for FGPP.

5.2 SO_2 AMBIENT MONITORING ANALYSIS

Ambient SO_2 monitoring data from existing monitoring stations are summarized in this section. Glades County and adjacent counties are classified as attainment for SO_2. The nearest SO_2 monitoring stations to the Site are located in Riviera Beach in Palm Beach County (AIRS No. 12-099-3004), approximately 123 km (74 miles) from the Site and in Sarasota in Sarasota County (AIRS No. 12-115-1006), approximately 140 km (84 miles) from the Site. These stations are operated by the FDEP and measure concentrations according to EPA procedures. These monitors are located in areas that have significantly more commercial and industrial activities than are present near the Site. As a result, the SO_2 monitoring data collected at these stations are likely to measure higher values than those near FGPP and will provide a conservative estimate of background concentrations.

As shown in Table 5-1, from 2003 through 2005, the second highest 24-hour average SO_2 concentration of 24 $\mu g/m^3$ was well below the AAQS of 260 $\mu g/m^3$, respectively. This observed concentration was used to represent background concentrations and added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

5.3 PM_{10} AMBIENT MONITORING ANALYSIS

Ambient PM_{10} monitoring data from existing monitoring stations are summarized in this section. Glades County and adjacent Counties are classified as attainment for PM_{10}. The nearest PM_{10} monitoring station to the Site is located in Belle Glade in Palm Beach County (AIRS No. 12-099-0008), approximately 53 km (85 miles) from the Site. This station is operated by the FDEP and measures concentrations according to EPA procedures. This monitor is located in areas that have significantly more commercial and industrial activities than are present near the Site. As a result, the PM_{10} monitoring data collected at this station is likely measure higher values than those near FGPP and will provide a conservative estimate of background concentrations.

As shown in Table 5-1, from 2003 through 2005, the second highest 24-hour average PM_{10} concentration of 38 $\mu g/m^3$ was well below the AAQS of 150 $\mu g/m^3$, respectively. This observed concentration was used to represent background concentrations and added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

TABLE 5-1
SUMMARY OF MAXIMUM MEASURED O3, SO2, AND PM$_{10}$ CONCENTRATIONS OBSERVED FROM REPRESENTATIVE MONITORING STATIONS, 2003 THROUGH 2005 FOR THE GLADES POWER PARK PROJECT

					Concentration									
					1-Hour		3-Hour		8-Hour		8-Hour	24-Hour		Annual
			Measurement Period								3-year Average			
AIRS No.	County	Location	Year	Months	Highest	2nd Highest	Highest	2nd Highest	Highest	2nd Highest	4th Highest	Highest	2nd Highest	Average
Ozone [a]		**Florida AAQS**			**NA**	**0.12 ppm**	**NA**	**NA**	**NA**	**NA**	**0.08 ppm**	**NA**	**NA**	**NA**
12-055-0003	Highlands	Sebring, 123 Main Drive	2005	Jan-Dec	0.079	0.079	NA	NA	NA	NA	0.072	NA	NA	NA
			2004	Jan-Dec	0.083	0.076	NA	NA	NA	NA	0.069	NA	NA	NA
			2003	Jan-Dec	0.093	0.084	NA	NA	NA	NA	NA	NA	NA	NA
Sulfur dioxide		**Florida AAQS**			**NA**	**NA**	**NA**	**0.5 ppm**	**0.5 ppm**	**0.5 ppm**	**NA**	**NA**	**0.1 ppm**	**0.02 ppm**
12-099-3004	Palm Beach	Riviera Beach, 1050 15th St. W	2005	Jan-Dec	NA	NA	0.003	0.003	0.003	0.003	NA	0.003	0.003	0.0012
			2004	Jan-Dec	NA	NA	0.002	0.002	0.002	0.002	NA	0.001	0.001	0.001
			2003	Jan-Dec	NA	NA	0.004	0.003	0.003	0.003	NA	0.002	0.002	0.001
12-115-1006	Sarasota	Sarasota, 4570 17th South	2005	Jan-Dec	NA	NA	0.024	0.015	0.015	0.015	NA	0.010	0.007	0.0013
			2004	Jan-Dec	NA	NA	0.014	0.014	0.014	0.014	NA	0.005	0.004	0.0012
			2003	Jan-Dec	NA	NA	0.026	0.024	0.024	0.024	NA	0.010	0.009	0.0016
PM$_{10}$		**Florida AAQS**			**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**150 µg/m^3**	**50 µg/m^3**
12-099-0008	Palm Beach	Belle Glade, 38754 State Road 80	2005	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	41	38	17.6
			2004	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	31	30	17.1
			2003	Jan-Dec	NA	NA	NA	NA	NA	NA	NA	30	28	16.4

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On July 18, 1997, EPA promulgated revised AAQS for O$_3$. The O$_3$ standard was modified to be 0.08 ppm for the 8-hour average; achieved when the 3-year average of 98th percentile value is 0.08 ppm or less.

Source: EPA Air Quality System, Quick Look Reports, Florida: 2003, 2004, and 2005.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 SIGNIFICANT IMPACT ANALYSIS APPROACH

6.1.1 SITE VICINITY (NEAR FIELD)

The general modeling approach for FGPP followed the EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to FGPP alone will result in predicted impacts that are in excess of the EPA significant impact levels.

If FGPP-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments.

6.1.2 PSD CLASS I AREAS (FAR FIELD)

Generally, if a major new facility is located within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to FGPP alone at the PSD Class I area. The Everglades NP is located about 113 km from the Site and Chassahowitzka NWA is located about 239 km from the Site. At the request of the FLM, the maximum predicted impacts at these Class I areas are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If FGPP-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then a cumulative analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

In addition, FGPP's maximum concentrations are evaluated at the PSD Class I area for pollutants whose emissions are greater than the significant emission rate, to address potential impacts on AQRV. This analysis includes evaluations of visibility and deposition impacts.

6.2 PRE-CONSTRUCTION MONITORING ANALYSIS APPROACH

The modeling approach followed EPA and FDEP modeling guidelines for evaluating a project's impacts relative to the *de minimis* monitoring levels to determine the need to submit ambient monitoring data prior to construction. Current FDEP policies stipulate that the predicted highest annual average and highest short-term concentrations are to be compared to the applicable *de minimis* monitoring levels.

6.3 AIR MODELING ANALYSIS APPROACH

6.3.1 GENERAL PROCEDURES

As stated in the previous sections, air modeling analyses are required to determine if FGPP's impacts are predicted to be greater than the significant impact levels and *de minimis* monitoring levels for each pollutant that is emitted above the significant emission rate. These analyses consider FGPP's impacts alone. Air quality impacts are predicted using 5 years of meteorological data and selecting the highest predicted ground-level concentrations for comparison to the significant impact levels and *de minimis* monitoring levels.

To predict the maximum annual and short-term concentrations for FGPP presented in Section 6.5, the modeling approach was divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred.

6.3.2 PSD CLASS II ANALYSIS

If FGPP's impacts are greater than the significant impact levels, the air modeling analyses must consider other nearby sources and background concentrations to predict a total concentration for comparison to AAQS. Because FGPP's maximum 24-hour average SO_2 and PM_{10} impacts are predicted to be greater than the significant impact level, additional AAQS and PSD Class II Increment analyses were performed for these pollutants and averaging times.

Generally, when using 5 years of meteorological data for the analysis, the highest annual and the highest, second-highest (HSH) short-term (i.e., 24 hours or less) concentrations are compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated each year for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

The HSH approach is consistent with AAQS and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

It should be noted that for determining compliance with the 24-hour AAQS for PM_{10}, the highest of the sixth-highest concentration predicted in 5 years (i.e., H6H), instead of the HSH concentration predicted for each year, is used to compare to the applicable 24-hour AAQS.

The AAQS analysis is a cumulative source analysis that evaluates whether the concentrations from all sources will comply with the AAQS. These concentrations include the modeled impacts from sources at the Site and from other nearby facility sources added to a background concentration. The background concentration accounts for sources not included in the modeling analysis.

The PSD Class II analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources will comply with the allowable PSD Class II increments. These concentrations include the modeled impacts from PSD increment-affecting sources at FGPP, plus nearby PSD increment-affecting sources at other facilities.

6.3.3 PSD CLASS I ANALYSIS

For each pollutant for which a significant impact is predicted at the PSD Class I area, a cumulative PSD Class I analysis is required. The PSD Class I analysis is a cumulative source analysis that evaluates whether the concentrations for increment-affecting sources located within 200 km of the PSD Class I area will comply with the allowable PSD Class I increments. These concentrations include the impacts from PSD increment-affecting sources at FGPP, plus the impacts from PSD increment-affecting sources at other facilities.

A modeling protocol was submitted to FDEP and the NPS on June 20, 2006 regarding the methods and procedures to be used. Comments were received on July 28, 2006. The protocol and comments are presented in Appendix G.

6.4 MODEL SELECTION

The selection of air quality models to calculate air quality impacts for FGPP must be based on the models' ability to simulate impacts in areas surrounding the Site as well as at the PSD Class I areas of the Everglades NP, located about 113 km from the Site, and Chassahowitzka NWA, located about 239 km from the Site. Two air quality dispersion models were selected and used in these analyses to address air quality impacts for FGPPt. These models were:

- The American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model, and
- The California Puff model (CALPUFF).

The AERMOD dispersion model (Version 04300) is available on the EPA's Internet web site, Support Center for Regulatory Air Models (SCRAM), within the Technology Transfer Network (TTN). A listing of AERMOD model features is presented in Table 6-1.

The EPA and FDEP recommend that the AERMOD model be used to predict pollutant concentrations at receptors located within 50 km from a source. The AERMOD model calculates hourly concentrations based on hourly meteorological data. The AERMOD model is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain.

The AERMOD model was used to predict the maximum pollutant concentrations due to FGPP in nearby areas surrounding the Site. The AERMOD model was also used to predict the maximum pollutant concentrations due to FGPP's emissions together with appropriate background sources. The predicted concentrations were then compared to the applicable AAQS and PSD Class II increments.

At distances beyond 50 km from a source, the CALPUFF model is recommended for use by the EPA and the Federal Land Manager (FLM). The CALPUFF model is a long-range transport model applicable for estimating the air quality impacts in areas that are more than 50 km from a source.

The CALPUFF model is maintained by the EPA on the SCRAM internet website. A listing of CALPUFF model features is presented in Table 6-2.

The methods and assumptions used in the CALPUFF model are based on the latest recommendations for modeling analysis as presented in the following reports:

- The Interagency Workgroup on Air Quality Models (IWAQM), *Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* (EPA, 1998); and
- The *Federal Land Manager's Air Quality Relative Values Workgroup (FLAG) Phase I Report* (December 2000).
- *Revised IMPROVE Algorithm for Estimating light Extinction from Particle Speciation Data* (Interagency Monitoring of Protected Visual Environments, November 2006).

In addition, updates to the modeling methods and assumptions were followed based on comments and discussions with the NPS.

The CALPUFF model was used to perform a significant impact analysis for FGPP at the PSD Class I areas of Everglades NP and Chassahowitzka NWA and to assess FGPP's potential impact on regional haze and total nitrogen and sulfur deposition levels.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA for rural mode and are referred to as the regulatory default options in the AERMOD model and, where applicable, the CALPUFF model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural mode,
5. Default vertical potential temperature gradients, and
6. Calm wind processing.

The EPA regulatory default options are used to address maximum impacts.

6.5 METEOROLOGICAL DATA

Meteorological data used in the AERMOD model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) offices located at the Ft. Myers Southwest and Tampa International Airports, respectively. Concentrations were predicted using 5 years of hourly meteorological data from 2001 through 2005. The NWS office at Ft. Myers is located approximately 70 km (42 miles) west of the Site. These data were provided by the FDEP which considers data from this station to have surface meteorological data representative of FGPP.

AERMOD incorporates land use parameters for determining boundary layer parameters that are used for dispersion. Based on the most recent regulatory guidance, the land use parameters should be representative of the data measurement site (i.e., NWS at Ft. Myers). Land use data, representing the average surface roughness, albedo, and Bowen ratio that exist within a 3-km radius of the NWS station at Ft. Myers were extracted from 1-degree land use files from the U.S. Geographical Survey (USGS) using the AERSURFACE program. AERSURFACE currently extracts land use data in 12 wind direction sectors covering 360 degrees. These parameters were compared to those estimated in the same manner around FGPP. Based on this comparison, the values for all parameters were similar.

For CALPUFF, the air modeling analysis was conducted using the latest meteorological and geophysical databases which have been developed for use with the most recent versions of CALPUFF. These datasets were prepared by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) for the purpose of conducting visibility impairment analyses under the Best Available Retrofit Technology (BART) Rule. A discussion of these databases can be found in Section 4.0 of the document entitled, *Protocol for the Application of the CALPUFF Model for Analyses of BART* (revised August 31, 2006).

For FGPP, the VISTAS Florida CALMET domain with 4-km spacing (VISTA refined Domain 2) was used. The data cover the period from 2001 to 2003. Golder obtained these datasets from the FDEP. The FDEP and FLM have recommended their use for PSD projects.

6.6 EMISSION INVENTORY

6.6.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the criteria pollutant emission rates, physical stack, and stack operating parameters for FGPP that were used in the air modeling analysis are presented in Table 2-2 and Appendix A. In an effort to obtain the maximum air quality impacts for a range of possible operating conditions, the air modeling for the boilers considered operating loads at 100, 75, and 40 percent.

The air modeling origin was assumed to be located at the stack for Boiler No. 1 and Boiler No.2. For PSD Class I modeling, the modeling origin was assumed to be located at UTM east and north coordinates of 483,041 and 2,973,720 m, respectively, in UTM Zone 17.

AERMOD was used to predict maximum concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times in the near-field areas of FGPP. To estimate impacts due to emissions from the boiler stacks, a total emission rate of 7.9365 lb/hr or 1.0 grams per second (g/s) was initially used. These modeling results produced relative concentrations as a function of the modeled emission rate (i.e., $\mu g/m^3$ per 1.0 g/s). These impacts are referred to as generic pollutant impacts. Maximum air quality impacts for specific pollutants were then determined by multiplying the maximum pollutant-specific emission rate in lb/hr (g/s) by the maximum predicted generic impact divided by the modeled emission rate [e.g., 7.9365 lb/hr (1.0 g/s)].

To address PM_{10} impacts from FGPP, the PM_{10} sources were modeled explicitly using the maximum PM_{10} emission rates. These sources included the boilers and material handling operations for coal, limestone, flyash, and gypsum. Detailed descriptions of these sources are presented in Section 2.0 and Appendix A.

For the PSD Class I areas, regional haze and sulfur and nitrogen deposition analyses were performed for FGPPwith the CALPUFF model based on the maximum hourly emissions for the boilers which is for 100-percent load conditions. Detailed descriptions of the operating conditions and pollutant emission factors and rates are provided in Appendix A.

6.6.2 AAQS AND PSD CLASS II ANALYSES

The maximum pollutant impacts for FGPP are predicted to be less than the significant impact levels for all pollutants and averaging periods except for SO_2 and PM_{10} for the 24-hour averaging periods.

As a result, cumulative source impact analyses are required to demonstrate compliance with the 24-hour average SO_2 and PM_{10} AAQS and PSD Class II increments.

Air quality concentrations were predicted within the area of significant impact for individual pollutants due to FGPP. A significant impact area (SIA) and the radius of the SIA were determined for each pollutant and averaging time combination for which FGPP's impact is predicted to be significant. The radius of impact is used as the basis for determining inventory of background sources to be included in the air impact analyses.

FGPP's SIA for the 24-hour average SO_2 and PM_{10} concentrations are predicted to extend out to 2 and 3.5 km, respectively, from the Site. For modeling purposes, the SO_2 SIA was assumed to extend out to 10 km.

Facilities located within the SIA were modeled explicitly (considered to be the modeling area). Facilities within the SIA plus 50 km were considered to be in the screening area. All facilities in the screening area were evaluated using the North Carolina screening technique. Based on this technique, facilities whose annual emissions (i.e., TPY) are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-SIA), where D is the distance in km from the facility to the Site.

Listings of SO_2 and PM_{10} sources that were used in the AAQS and PSD Class II analyses and their locations relative to FGPP are provided in Tables 6-3 and 6-4, respectively. Data for sources were obtained from FDEP. Detailed SO_2 and PM_{10} source data that were used for the AAQS and PSD Class II increment analyses are presented in Appendix C.

6.6.3 PSD CLASS I ANALYSIS

The maximum FGPP impacts at the PSD Class I area of the Everglades NP and Chassahowitzka NWA are predicted to be less than the proposed PSD Class I significant impact levels for all pollutants and averaging periods except for SO_2 for the 3-hour and 24-hour averaging periods at the Everglades NP. As a result, cumulative source impact analyses are required to demonstrate compliance with the 3-hour and 24-hour average SO_2 PSD Class I increments at the Everglades NP. Data for these sources were also obtained from FDEP.

A listing of SO_2 sources that were used in the PSD Class I analyses and their locations relative to the PSD Class I area are provided in Table 6-4. PSD sources located within 200 km of the Class I area were included in the PSD Class I modeling analysis. Detailed SO_2 source data that were used for the PSD Class I analyses are presented in Appendix C.

6.7 BUILDING DOWNWASH EFFECTS

All significant building structures in FGPP area were identified by the Site plot plan (see Figure 2-2). The building structures were processed in the EPA Building Profile Input Program [(BPIP), Version 95086] program to determine direction-specific building heights and widths for each 10-degree azimuth direction for each source that was included in the modeling analysis. A listing of dimensions for each structure is presented in Table 6-6. See Appendix D for plots of these building structures.

Based on this evaluation, the GEP stack height for FGPP was determined to be 512 ft. Therefore, building downwash effects were included in the air modeling analyses.

6.8 RECEPTOR LOCATIONS

6.8.1 SITE VICINITY

To determine the maximum impact for all pollutants and averaging times in the vicinity of FGPP, concentrations were predicted at receptors located in a detailed receptor grids centered on the proposed stack, the modeling origin, and extended from the plant property out to 20 km.

Along the plant boundary, a Cartesian receptor grid was used to predict concentrations for FGPP at more than 300 receptors spaced at 50-m intervals.

In addition, a general Cartesian grid was used to predict concentrations beyond the plant property out to 20 km. Receptors were located at the following intervals and distances from the origin:

- Every 100 m from the plant property to 3,000 m;
- Every 250 m from 3,250 to 5,000 m;
- Every 500 m from 5,500 to 7,000 m; and
- Every 1,000 m from 7,000 to 10,000 m.

More than 3,500 receptors were used in the analysis to determine the maximum impacts for FGPP.

6.8.2 CLASS I AREA

For the determining FGPP's impacts at the PSD Class I areas, pollutant concentrations were predicted in an array of 901 discrete receptors located at the PSD Class I area of the Everglades NP and 113 discrete receptors located at the PSD Class I area of the Chassahowitzka NWA. These receptors were obtained from the National Park Service (NPS).

6.9 BACKGROUND CONCENTRATIONS

Background concentrations are necessary to determine total ambient air quality impacts to demonstrate compliance with the AAQS. "Background concentrations" are defined as concentrations due to sources other than those specifically included in the modeling analysis. For all pollutants, background would include other point sources not included in the modeling (i.e., distant sources or small sources), fugitive emission sources, and natural background sources. In general, monitoring data collected near the area in which the air quality impact is performed is used for this purpose.

Summaries of ambient SO_2 and PM_{10} concentrations measured are presented in Section 5.0. For purposes of determining an ambient background concentration for use in the modeling analysis, the second-highest 24-hour average SO_2 and PM_{10} concentrations were selected to represent background concentrations.

6.10 MODEL RESULTS

6.10.1 PSD CLASS II SIGNIFICANT IMPACT ANALYSIS

The maximum pollutant concentrations predicted for FGPP are given in Tables 6-7 and 6-8. The maximum concentrations predicted for the boilers only are presented in Table 6-7. The maximum concentrations for FGPP, including PM_{10} concentrations predicted for the boilers and material handling operations, for comparison to the PSD Class II significant impact levels, are presented in Table 6-8.

The modeling results indicate that maximum concentrations due to FGPP are predicted to be less than the significant impact levels for all pollutants, except SO_2 for the 24-hour averaging periods. As a result, additional modeling analyses are required only to demonstrate compliance with the 24-hour average SO_2 AAQS and PSD Class II increments.

6.10.2 PSD CLASS I SIGNIFICANT IMPACT ANALYSIS

The maximum SO_2, NO_2, and PM_{10} concentrations predicted for FGPP at the PSD Class I areas of the Everglades NP and Chassahowitzka NWA are given in Table 6-9. As shown, the maximum FGPP impacts at the PSD Class I area of the Everglades NP are predicted to be less than the proposed PSD Class I significant impact levels for the SO_2, PM_{10}, and NO_2 except for SO_2 for the 3- and 24-hour averaging periods. The maximum FGPP impacts at the PSD Class I area of the Chassahowitzka NP are predicted to be less than the proposed PSD Class I significant impact levels for SO_2, PM_{10}, and NO_2.

As a result, cumulative source impact analyses are required to demonstrate compliance with the 3- and 24-hour average SO_2 PSD Class I increments at the Everglades NP.

6.10.3 CUMULATIVE SO_2 AAQS ANALYSIS

A summary of the results of the cumulative SO_2 AAQS analysis for the 24-hour average SO_2 concentrations is presented in Table 6-10. The cumulative SO_2 impacts are the total air quality impacts due to FGPP and other modeled sources added to a non-modeled background concentration.

As shown in this table, the highest, second-highest 24-hour average SO_2 concentrations are predicted to be 40 $\mu g/m^3$ for the 24-hour averaging time, which is well below the AAQS of 260 $\mu g/m^3$.

A summary of the results of the cumulative PM_{10} AAQS analysis for the 24-hour average PM_{10} concentrations is also presented in Table 6-10. As shown in this table, the highest, second-highest 24-hour average PM_{10} concentrations are predicted to be 44 $\mu g/m^3$ for the 24-hour averaging time, which is well below the AAQS of 150 $\mu g/m^3$.

6.10.4 CUMULATIVE SO_2 PSD CLASS II INCREMENT ANALYSIS

A summary of the results of the cumulative PSD Class II increment analyses (i.e., impacts due to PSD increment-affecting sources) for the 24-hour average SO_2 concentrations is presented in Table 6-11.

The highest, second-highest 24-hour average SO_2 concentrations due to FGPP and other PSD increment-affecting sources are predicted to be 6.8 $\mu g/m^3$ for the 24-hour averaging time, which is below the allowable 24-hour PSD Class II increment of 91 $\mu g/m^3$.

A summary of the results of the cumulative PSD Class II increment analyses for the 24-hour average PM_{10} concentrations is also presented in Table 6-11. The highest, second-highest 24-hour average PM_{10} concentrations due to FGPP and other PSD increment-affecting sources are predicted to be 6 $\mu g/m^3$ for the 24-hour averaging time, which is well below the allowable 24-hour PSD Class II increment of 30$\mu g/m^3$.

6.10.5 CUMULATIVE SO_2 PSD CLASS I INCREMENT ANALYSIS

A summary of the results of the cumulative PSD Class I increment analyses (i.e., impacts due to PSD increment-consuming sources) for the 3- and 24-hour average SO_2 concentrations predicted at the Everglades NP are presented in Table 6-12.

The HSH 3- and 24-hour average SO_2 concentrations due to FGPP and other PSD increment-affecting sources are predicted to be 8.05 and 3.67 $\mu g/m^3$ for the 24-hour averaging time, which is below the allowable 3- and 24-hour PSD Class I increments of 25 and 5$\mu g/m^3$, respectively.

6.11 CONCLUSIONS

Based on these air quality modeling analyses, the maximum pollutant concentrations due to FGPP are predicted to be less than the PSD Class II and I significant impact levels for all pollutants except the 24-hour average SO_2 PSD Class II significant impact level and the 3- and 24-hour average SO_2 PSD Class I significant impact levels at the Everglades NP. As a result, more detailed SO_2 modeling analyses were performed with background sources to address compliance with the AAQS and PSD Class II and PSD Class I increments. The results of the modeling analysis demonstrate that FGPP will not have a significant affect on air quality and will comply with all applicable AAQS and PSD increments. Indeed, the modeling results clearly demonstrate that Florida's air quality will be protected.

TABLE 6-1

MAJOR FEATURES OF THE AERMOD MODEL, VERSION 04300

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function.
• In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface.
• Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference.
• Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources.
• Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities.
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash.
• Has capability of simulating point, volume, area, and multi-sized area sources.
• Accounts for the effects of vertical variations in wind and turbulence (Brower *et al.*, 1998).
• Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower *et al.*, 1998).
• Concentration estimates for 1-hour to annual average times.
• Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels.
• Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation.
• Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, Albedo, and Bowen ratio.
• Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux.
• The method of Pasquill (1976) to account for buoyancy-induced dispersion.
• A default regulatory option to set various model options and parameters to EPA-recommended values.
• Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = The American Meteorological Society and Environmental Protection Agency Regulatory Model.

Source: Paine *et al.*, 2004.

TABLE 6-2

MAJOR FEATURES OF THE CALPUFF MODEL, VERSION 5.756

CALPUFF Model Features
• Source types: Point, line (including buoyancy effects), volume, area (buoyant, non-buoyant)
• Non-steady-state emissions and meteorological conditions (time-dependent source and emission data; gridded 3-dimensional wind and temperature fields; spatially-variable fields of mixing heights, friction velocity, precipitation, Monin-Obukhov length; vertically and horizontally-varying turbulence and dispersion rates; time-dependent source and emission data for point, area, and volume sources; temporal or wind-dependent scaling factors for emission rates)
• Efficient sampling function (integrated puff formulation; elongated puff (slug) formation)
• Dispersion coefficient options (Pasquill-Gifford (PG) values for rural areas; McElroy-Pooler values (MP) for urban areas; CTDM values for neutral/stable; direct measurements or estimated values)
• Vertical wind shear (puff splitting; differential advection and dispersion)
• Plume rise (buoyant and momentum rise; stack-tip effects; building downwash effects; partial plume penetration above mixing layer)
• Building downwash effects (Huber-Snyder method; Schulman-Scire method)
• Complex terrain effects (steering effects in CALMET wind field; puff height adjustments using ISC model method or plume path coefficient; enhanced vertical dispersion used in CTDMPLUS)
• Subgrid scale complex terrain (CTSG option) (CTDM flow module; dividing streamline as in CTDMPLUS)
• Dry deposition (gases and particles; options for diurnal cycle per pollutant, space and time variations with a resistance model, or none)
• Overwater and coastal interaction effects (overwater boundary layer parameters; abrupt change in meteorological conditions, plume dispersion at coastal boundary; fumigation; option to use Thermal Internal Boundary Layers (TIBL) into coastal grid cells)
• Chemical transformation options (Pseudo-first-order chemical mechanisms for SO_2, SO_4, HNO_3, and NO_3; Pseudo-first-order chemical mechanisms for SO_2, SO_4, NO, NO_2, HNO_3, and NO_3 (RIVAD/ARM3 method); user-specified diurnal cycles of transformation rates; no chemical conversions)
• Wet removal (scavenging coefficient approach; removal rate as a function of precipitation intensity and type)
• Graphical user interface
• Interface utilities (scan ISC-PRIME and AUSPLUME meteorological data files for problems; translate ISC-PRIME and AUSPLUME input files to CALPUFF input files)

Note: CALPUFF = California Puff Model

Source: EPA, 2004.

TABLE 6-3
SUMMARY OF SO_2 EMITTING FACILITIES IN THE VICINITY OF THE GLADES POWER PROJECT

			UTM Coordinates		Relative to FPL Glades Power Project[a]						
Plant ID	Facility Name	County	East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] 20 km x (Dist.-SIA)	Include in Modeling Analysis ?
Modeling Area [d]											
0430008	Atlas-Transoil Inc.		489.2	2966.6	6.2	-7.1	139.1	9.4	47	188.3	No
Screening Area [d]											
0510015	Southern Gardens Citrus Processing Corp.	Hendry	487.5	2957.6	4.5	-16.1	164.5	16.7	491	134.5	Yes
	Glades Electric Cooperative	Hendry	487.1	2957.5	4.0	-16.2	166.1	16.7	17.7	134.7	No
0510003	U.S. Sugar Corp. Clewiston Mill	Hendry	506.1	2956.9	23.1	-16.8	126.1	28.5	1,742	370.8	Yes
0510004	A. Duda & Sons, Inc. / Citrus Belle	Hendry	456.4	2950.3	-26.6	-23.4	228.7	35.5	142	509.4	No
0550005	Georgia Pacific Corp. - Lake Placid	Highlands	466.98	3009.23	-16.1	35.5	335.7	39.0	59	579.5	No
0550014	Better Roads, Inc.	Highlands	465.6	3008.7	-17.4	35.0	333.5	39.1	53	581.7	No
0930001	Okeechobee Asphalt	Okeechobee	516.09	3014.21	33.0	40.5	39.2	52.3	105	845.3	No
0990005	Okeelanta Corp.	Palm Beach	524.9	2940.1	41.9	-33.6	128.8	53.7	37	873.8	No
0990332	New Hope Power Partnership	Palm Beach	524.92	2939.44	41.9	-34.3	129.3	54.1	1,035	882.4	Yes
0990594	El Paso Merchant Energy Company	Palm Beach	533.5	2954.1	50.5	-19.6	111.2	54.1	363	882.8	No
0710193	Calumet Florida LLC	Lee	442.61	2937.17	-40.4	-36.5	227.9	54.5	11	890.1	No
0990061	U.S. Sugar Corp. Bryant Mill	Palm Beach	537.83	2969.12	54.8	-4.6	94.8	55.0	1,141	899.6	Yes
0990026	Sugar Cane Growers Co-Op	Palm Beach	534.9	2953.3	51.9	-20.4	111.5	55.7	2,083	914.7	Yes
7770048	Better Roads, Inc.		425	2963.3	-58.0	-10.4	259.8	59.0	29	979.4	No
Extended Screening Area [d]											
0930109	BP Technology Inc.	Okeechobee	525.18	3017.4	42.1	43.7	44.0	60.7	16	1,013.9	No
0150028	Ajax Paving Industries		422.7	2963.9	-60.3	-9.8	260.8	61.1	75	1,022.7	No
0990019	Osceola Farms	Palm Beach	544.2	2968	61.2	-5.7	95.3	61.4	640	1,028.5	Yes
0850001	Florida Power & Light (PMR) - Martin		542.68	2992.65	59.6	18.9	72.4	62.6	63,179	1,051.4	Yes
0710002	Florida Power & Light (PFM) - Fort Myers	Lee	422.3	2952.9	-60.7	-20.8	251.1	64.2	21,225	1,084.2	Yes
0550018	Tampa Electric Company		464.3	3035.4	-18.7	61.7	343.1	64.5	4,046	1,089.3	Yes
0710119	Lee County Dept. of Solid Waste Mgt.	Lee	424.21	2945.7	-58.8	-28.0	244.5	65.2	327	1,103.3	No
0710133	Waste Management, Inc. of Florida	Lee	424.97	2942.83	-58.1	-30.9	242.0	65.8	55	1,115.5	No
0850102	Indiantown Cogeneration, L.P.		547.65	2990.7	64.6	17.0	75.3	66.8	2,566	1,136.1	Yes
0710187	APAC-Southeast, Inc.	Lee	428.03	2930.36	-55.0	-43.4	231.8	70.0	65	1,200.9	No
0110351	South Florida Water Management District		522.26	2912.27	39.2	-61.4	147.5	72.9	21	1,258.0	No
0710065	APAC-Southeast, Inc.	Lee	424.3	2930.2	-58.7	-43.5	233.5	73.1	90	1,262.1	No

TABLE 6-3
SUMMARY OF SO_2 EMITTING FACILITIES IN THE VICINITY OF THE GLADES POWER PROJECT

			UTM Coordinates		Relative to FPL Glades Power Project[a]						
Plant ID	Facility Name	County	East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)	Q, (TPY) Emission Threshold [b,c] 20 km x (Dist.-SIA)	Include in Modeling Analysis ?
0550004	TECO-Sebring/Dinner Lake	Highlands	456.8	3042.5	-26.2	68.8	339.1	73.6	1,313	1,272.3	Yes
0270016	Desoto County Generating Company, LLC		419.75	3011.5	-63.3	37.8	300.8	73.7	119	1,274.2	No
0710004	Gulf Paving Co.	Lee	415.2	2944.1	-67.8	-29.6	246.4	74.0	85	1,280.5	No
0990016	Atlantic Sugar Association	Palm Beach	552.9	2945.2	69.9	-28.5	112.2	75.5	555	1,309.1	No
0710171	Amerimix Industries, Inc.	Lee	415.54	2930.96	-67.5	-42.8	237.6	79.9	96	1,398.1	No
0990630	South Florida Materials Corp.	Palm Beach	540.9	2918.5	57.9	-55.2	133 7	80.0	50	1,399.6	No
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	67.9	44.4	56.8	81.1	76	1,421.7	No
0990530	Hubbard Construction Company	Palm Beach	562.14	2955.56	79.1	-18.2	102.9	81.2	48	1,423.1	No
0270003	Peace River Citrus Products		409.8	3010.1	-73.2	36.4	296.4	81.8	86	1,435.6	No
0150002	Asphalt Developers		400.7	2977.6	-82.3	3.9	272.7	82.4	38	1,448.6	No
0990349	South Florida Water Management District	Palm Beach	562.55	2951.32	79.5	-22.4	105.7	82.6	17	1,452.1	No
0550003	Florida Power Corp D/B/A Progress Energy F	Highlands	451.4	3050.5	-31.6	76.8	337.6	83.0	5,054	1,460.9	Yes
0710236	Bonita Springs Utilities, Inc.	Lee	424.1	2915	-58.9	-58.7	225.1	83.2	15	1,464.0	No
0990021	United Technologies Corporation	Palm Beach	568.41	2975.84	85.4	2.1	88.6	85.4	571	1,507.9	No
1110107	Treasure Coast Land Clearing	St. Lucie	545.7	3035.2	62.7	61.5	45.5	87.8	15	1,555.7	No
0210023	APAC-Southeast, Inc.		429.2	2898.8	-53.8	-74.9	215.7	92.3	97	1,645.2	No
0210051	Waste Management Inc. of Florida		434.58	2893.22	-48.5	-80.5	211.0	94.0	938	1,679.2	No
1110004	Tropicana Products, Inc	St. Lucie	559.61	3028.32	76.6	54.6	54.5	94.0	22	1,680.8	No
1110060	Florida Gas Transmission Company	St. Lucie	557.24	3035.78	74.2	62.1	50.1	96.7	11	1,734.6	No
1110010	Dickerson Florida, Inc.	St. Lucie	562.24	3030.36	79.2	56.6	54.4	97.4	83	1,747.4	No
0850021	Stuart Contracting	Martin	575.2	3006.8	92.2	33.1	70.3	97.9	100	1,758.3	No
7774818	Better roads, Inc.		432 5	2889.7	-50.5	-84.0	211.0	98.0	53	1,761.0	No
0990087	Ranger Construction Industries, Inc.	Palm Beach	579.9	2951.7	96.9	-22.0	102.8	99.3	94	1,786.6	No

[a] The FPL Glades Power Project is located at UTM Coordinates: East 483.0 km
North 2973.7 km

[b] The modeling area or significant impact area (SIA) for the project is estimated to be 10.0 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the modeling area and its emission rate is greater than the product of "20 km x (Distance - SIA)".

[d] "Modeling Area" is the area in which the Project is predicted to have a significant impact. EPA recommends that all sources within this area be modeled.
"Screening Area" is the area that is 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.
"Extended Screening Area" is the area beyond the screening area and out to 100 km in which only large sources are included in the modeling.

TABLE 6-4
SUMMARY OF PM_{10} EMITTING FACILITIES IN THE VICINITY OF THE GLADES POWER PROJECT

			UTM Coordinates		Relative to FPL Glades Power Project[a]						
Plant ID	Facility Name	County	East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum PM Emissions (TPY)	Q, (TPY) Emission Threshold[b,c] 20 x (Dist.-SIA)	Include in Modeling Analysis ?
Modeling Area[d]											
No sources located within the modeling area.											
Screening Area[d]											
7775172	Better Roads Inc., Alico Road Asphalt Plant	Glades	492.0	2966.0	8.9	-7.7	131	11.8	22	172	NO
0510022	Fiberstar, Inc	Hendry	487.7	2957.7	4.6	-16.1	164	16.7	91	270	NO
510015	Southern Gardens Citrus	Hendry	487.6	2957.6	4.6	-16.1	164	16.8	82	271	NO
510003	U.S. Sugar Corp. Clewiston Mill	Hendry	506.1	2956.9	23.1	-16.8	126	28.5	1,641	507	YES
0510004	A. Duda & Sons, Inc - Citrus Belle	Hendry	456.4	2950.3	-26.6	-23.4	229	35.5	21	645	NO
0550005	Georgia Pacific Corporation	Highlands	467.0	3009.2	-16.1	35.5	336	39.0	21	715	NO
0550014	Better Roads, Inc. - Lake Placid Asphalt Plant	Highlands	465.6	3008.7	-17.4	35.0	333	39.1	18	718	NO
Beyond Screening Area out to 100 km[d]											
990005	Okeelanta Corp.	Palm Beach	524.7	2939.5	41.7	-34.2	129	53.9	34	1,014	YES[c]
7775215	Daniel P. Mays - Church Road Site	Hendry	445.8	2934.5	-37.2	-39.2	223	54.1	44	1,017	NO
990332	New Hope Power Partnership (Okeelanta Cogeneration Plant)	Palm Beach	524.9	2939.4	41.9	-34.3	129	54.1	269	1,018	YES
990594	El Paso Merchant Energy Company, Belle Glade Energy Center	Palm Beach	533.5	2954.1	50.5	-19.6	111	54.1	179	1,019	NO
990061	U.S. Sugar Corp. - Bryant Mill	Palm Beach	537.8	2969.1	54.8	-4.6	95	55.0	1,223	1,036	YES
990026	Sugar Cane Growers Cooperative	Palm Beach	534.9	2953.3	51.9	-20.4	111	55.7	1,769	1,051	YES
0150028	Ajax Paving Industries - Tuckers Corner	Charlotte	422.7	2963.9	-60.3	-9.8	261	61.1	29	1,159	NO
990019	Osceola Farms	Palm Beach	544.2	2968.0	61.2	-5.7	95	61.4	617	1,165	NO
850001	FPL - Martin Power Plant	Martin	542.7	2992.7	59.6	18.9	72	62.6	8,580	1,187	YES
0710002	FPL - Fort Myers Power Plant	Lee	422.3	2952.9	-60.7	-20.8	251	64.2	3,078	1,220	YES
0550018	Tampa Electric Company - Phillips Station	Highlands	464.3	3035.4	-18.7	61.7	343	64.5	143	1,225	NO
0710119	Lee County Dept. of Solid Waste Mangement	Lee	424.2	2945.7	-58.8	-28.0	245	65.2	52	1,239	NO
0550006	Genpak LLC	Highlands	464.8	3036.8	-18.3	63.1	344	65.7	108	1,250	NO
0550032	Turf Care Supply Corp. Erieview TWR - Sebring Plant	Highlands	469.5	3038.4	-13.5	64.7	348	66.1	95	1,258	NO
0850102	Indiantown Cogeneration, L.P.	Martin	547.7	2990.7	64.6	17.0	75	66.8	271	1,272	NO
0850012	Bay State Milling Co	Martin	547.4	2991.7	64.4	18.0	74	66.8	94	1,272	NO
0850002	Louis Dreyfus Citrus, Inc. - Indiantown Plant	Martin	548.0	2991.5	64.9	17.8	75	67.3	172	1,282	NO
0710187	Oldcastle Materials, Inc. - Lee County Drum Mix Asphalt Plant	Lee	428.0	2930.4	-55.0	-43.4	232	70.0	24	1,337	NO
0710126	Rinker Materials Corp. - Ft. Meyers Mine	Lee	427.0	2931.0	-56.0	-42.7	233	70.5	54	1,345	NO
0110351	South Florida Water Mgmt. District - Pump Stn. S-8 and G-404	Broward	522.3	2912.3	39.2	-61.4	147	72.9	23	1,394	NO
0710004	Gulf Paving Co.	Lee	415.2	2944.1	-67.8	-29.6	246	74.0	71	1,417	NO
990016	Atlantic Sugar Association	Palm Beach	552.9	2945.2	69.9	-28.5	112	75.5	763	1,445	NO
7775296	Pro Disposal Inc. - Supply Drive	Lee	418.1	2930.9	-64.9	-42.8	237	77.8	30	1,491	NO
7770060	Ajax Paving Industries Inc. of Florida	Lee	417.7	2930.8	-65.3	-42.9	237	78.1	24	1,499	NO
990021	Pratt & Whitney (United Technologies)	Palm Beach	562.0	2976.0	79.0	2.3	88	79.0	121	1,516	NO
0710171	Amerimix Industries, Inc. - Ft. Myers Sand/Cement Blending & Bagging	Lee	415.5	2931.0	-67.5	-42.8	238	79.9	18	1,534	NO
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	67.9	44.4	57	81.1	61	1,558	NO
0990348	Palm Beach Aggregates, Inc.	Palm Beach	563.0	2952.0	80.0	-21.7	105	82.9	83	1,593	NO
0710236	Bonita Springs Utilities, Inc. - East Water Reclamation Facility	Lee	424.1	2915.0	-58.9	-58.7	225	83.2	25	1,600	NO
0990021	United Technologies Corp. - Pratt & Whitney Aircraft	Palm Beach	568.4	2975.8	85.4	2.1	89	85.4	121	1,644	NO
0210023	Oldcastle Materials, Inc. - Collier County Asphalt Concrete Plant	Collier	429.2	2898.8	-53.8	-74.9	216	92.3	43	1,781	NO
1110004	Tropicana Products, Inc.	St. Lucie	559.6	3028.3	76.6	54.6	55	94.0	175	1,817	NO
1110040	Ranger Construction Industries, Inc. - Ranger/Ft. Pierce	St. Lucie	561.7	3030.2	78.6	56.5	54	96.8	41	1,872	NO
1110010	Dickerson Florida, Inc. - Dickerson/Asphalt Plant #14	St. Lucie	562.2	3030.4	79.2	56.6	54	97.4	54	1,883	NO
0990087	Ranger Construction Industries, Inc. - West Palm Plant	Palm Beach	579.9	2951.7	96.9	-22.0	103	99.3	22	1,923	NO

[a] The FPL Glades Power Project is located at UTM Coordinates East 483.0 km
North 2973.7 km

[b] The modeling area or significant impact area (SIA) for the project is estimated to be 3.2 km

[c] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the modeling area and its emission rate is greater than the product of "20 km x (Distance - SIA)".

[d] "Modeling Area" is the area in which the Project is predicted to have a significant impact. EPA recommends that all sources within this area be modeled.
"Screening Area" is the area that is 50 km beyond the modeling area. EPA recommends that sources be modeled that are expected to have a significant impact in the modeling area.
"Beyond Screening Area out to 100 km" is the area beyond the screening area and out to 100 km in which only large sources are included in the modeling.

[e] Includes PSD expanding sources.

TABLE 6-5

SUMMARY OF SO_2 EMITTING FACILITIES INCLUDED IN THE PSD CLASS I INCREMENT CONSUMPTION ANALYSIS AT THE EVERGLADES NP FOR FGPP

			UTM Coordinates		Relative to Everglades NP [a]				Maximum SO_2
Plant ID	Facility Name	County	East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Emissions (TPY)
0250003	FPL Turkey Point Expansion	Dade	567.2	2813.2	56.5	0.8	89 2	56.5	39,989
0250348	Miami-Dade RRF/Montenay	Dade	563.8	2857.6	53.1	45.2	49.6	69.7	857
0250020	Tarmac - Pennsuco Cement Plant	Dade	562.9	2861 7	52.2	49.3	46.7	71.8	2.792
									-493
7775212	WEEKLEY ASPHALT PAVING, INC.		557.31	2880.6	46.6	68.2	34.4	82.6	60
0112410	South Florida Water Management District	Broward	555.1	2882.44	44.4	70.0	32.4	82.9	49
0112149	Fred Hunter's Memorial Services, Inc	Broward	578.6	2878.5	67.9	66.1	45.8	94.8	1.00
0112119	Wheelabrator South Broward, Inc.	Broward	578.87	2883.39	68.2	70.9	43.9	98.4	462
0110037	Florida Power & Light (FPL) - Fort Lauderda	Broward	579.39	2883.36	68.7	70.9	44.1	98.8	1,715
									-15,886
0210090	Calumet Florida L.L.C.	Collier	470.07	2904.23	-40.6	91.8	336.1	100.4	5.45
0110351	South Florida Water Management District	Broward	522.26	2912.27	11.6	99.8	6 6	100.5	20.6
0210018	Florida Rock Industries	Collier	467.8	2905.8	-42.9	93.4	335.3	102.7	3 10
0110036	FPL -Port Everglades	Broward	587.4	2885.3	76.7	72.9	46.5	105.8	170,215
7774818	Better Roads, Inc		432.5	2889.7	-78.2	77.3	314.7	109.9	52.6
0210051	Waste Management Inc. of Florida	Collier	434.58	2893.22	-76.1	80.8	316 7	111.0	938
0210039	Collier County Domestic Animal Services	Collier	429.32	2891.31	-81.3	78.9	314.1	113.3	3 29
0210023	APAC-Southeast, Inc	Collier	429.2	2898.8	-81.5	86.4	316.7	118.7	97.0
0112534	Enron/Deerfield Beach Energy Center	Broward	583 1	2907.9	72 4	95.5	37.2	119.8	166
0112120	North Broward Resource Recovery	Broward	583.6	2907.6	72.9	95.2	37.5	119.9	896
0210045	Naples Community Hospital	Collier	420 2	2892.5	-90.5	80.1	311.5	120.8	39.2
0990332	New Hope Power Partnership	Palm Beach	524.92	2939.44	14.3	127.0	6.4	127.8	1,035
0990005	Okeelanta Corp.	Broward	524.7	2939.5	14.0	127.1	6.3	127.8	37.0
									-333.6
0710236	Bonita Springs Utilities, Inc.	Lee	424.1	2915	-86.6	102.6	319.8	134.2	14.9
0990016	Atlantic Sugar Association	Palm Beach	552.9	2945.2	42 2	132.8	17.6	139.3	555
									-2,342
0710193	Calumet Florida LLC	Lee	442.61	2937.17	-68 1	124.7	331.4	142.1	10.7
0990026	Sugar Cane Growers Co-Op	Palm Beach	534.9	2953.3	24.2	140.9	9.8	142.9	2,083
									-15.214
0710187	APAC-Southeast, Inc.	Lee	428.03	2930.36	-82.6	117.9	325.0	144.0	65.2
0510003	U.S. Sugar Corp. Clewiston Mill	Hendry	506.1	2956.9	-4.6	144.5	358.2	144.5	1.742
									-5.917
0710065	APAC-Southeast, Inc.	Lee	424.3	2930.2	-86 4	117.8	323.7	146.0	90.3
	Glades Electric Cooperative	Glades	487.1	2957.5	-23.6	145.0	350.8	146.9	242
0510015	Southern Gardens Citrus Processing Corp.	Hendry	487.5	2957.6	-23.2	145.2	350.9	147.0	491
0510004	A. Duda & Sons, Inc - Citrus Belle	Hendry	456.4	2950.3	-54.3	137.9	338.5	148.1	142
0990349	South Florida Water Management District	Palm Beach	562.55	2951.32	51.9	138 9	20.5	148.3	17.5
	FPL West County Energy Center	Palm Beach	562.2	2953	51.5	140.6	20.1	149.7	571
0710171	Amerimix Industries, Inc.	Lee	415 54	2930.96	-95.1	118.5	321.2	152.0	95.6
0990530	Hubbard Construction Company	Palm Beach	562.14	2955.56	51.5	143.1	19.8	152.1	47.6
0990045	Lake Worth Utilities	Palm Beach	592.8	2943.7	82.1	131.3	32.0	154.8	7,415
0990087	Ranger Construction Industries, Inc	Palm Beach	579.9	2951.7	69.2	139.3	26.4	155.5	94.1
0430008	Atlas-Transoil Inc.	Glades	489.2	2966.6	-21.5	154.2	352.1	155.6	46 7
0990310	Community Asphalt Corp	Palm Beach	582.3	2950.8	71.6	138.4	27 4	155.8	137
0710133	Waste Management, Inc. of Florida	Lee	424.97	2942.83	-85.7	130.4	326.7	156.0	54.7
0710119	Lee County Dept. of Solid Waste Mgt.	Lee	424.21	2945.7	-86.5	133.3	327.0	158.8	327
0990061	U.S. Sugar Corp. Bryant Mill	Palm Beach	537.83	2969.12	27.2	156.7	9.8	159.0	1,141
									-3.806
0990019	Osceola Farms	Palm Beach	544.2	2968	33.5	155.6	12.2	159.1	640
									-1.469
0710004	Gulf Paving Co.	Lee	415.2	2944.1	-95.5	131 7	324.1	162.6	85.2
0710002	Florida Power & Light (FPL) - Fort Myers Pl	Lee	422.3	2952.9	-88.4	140 5	327.8	165.9	21,225
									-66,725
0990234	Solid Waste Authority of PBC	Palm Beach	585.8	2960.5	75.1	148.0	26.9	166.0	1,533
0990042	FPL -Riviera Beach	Palm Beach	594.2	2960 6	83.5	148.2	29.4	170.1	73,475
0990021	United Technologies Corporation	Palm Beach	568.41	2975.84	57.7	163.4	19.5	173.3	571

TABLE 6-5

SUMMARY OF SO_2 EMITTING FACILITIES INCLUDED IN THE PSD CLASS I INCREMENT CONSUMPTION ANALYSIS AT THE EVERGLADES NP FOR FGPP

			UTM Coordinates		Relative to Everglades NP[a]				Maximum SO_2
Plant ID	**Facility Name**	**County**	**East (km)**	**North (km)**	**X (km)**	**Y (km)**	**Direction (deg.)**	**Distance (km)**	**Emissions (TPY)**
7770048	Better Roads, Inc.		425	2963.3	-85.7	150.9	330.4	173.5	29.0
0150028	Ajax Paving Industries	Charlotte	422.7	2963.9	-88.0	151.5	329.9	175.1	74.6
0850102	Indiantown Cogeneration, L.P.	Martin	547.65	2990.7	37.0	178.3	11.7	182.1	2,566
0850001	Florida Power & Light (FPL) - Martin Power	Martin	542.68	2992.65	32.0	180.2	10.1	183.0	63,179
0150002	Asphalt Developers	Charlotte	400.7	2977.6	-110.0	165.2	326.3	198.4	37.8
0550014	Better Roads, Inc.	Highlands	465.6	3008.7	-45.1	196.3	347.1	201.4	52.7
0550005	Georgia Pacific Corp.	Highlands	466.98	3009.23	-43.7	196.8	347.5	201.6	59.2
0930001	Okeechobee Asphalt	Okeechobee	516.09	3014.21	5.4	201.8	1.5	201.8	105
0850021	Stuart Contracting	Martin	575.2	3006.8	64.5	194.4	18.4	204.8	100
0930109	BP Technology Inc.	Okeechobee	525.18	3017.4	14.5	205.0	4.1	205.5	15.8
1110103	CPV Cana, LTD.	St. Lucie	550.9	3018.1	40.2	205.7	11.1	209.6	76.0
0270016	Desoto County Generating Company, LLC	Desoto	419.75	3011.5	-90.9	199.1	335.5	218.8	119
1110004	Tropicana Products, Inc.	St. Lucie	559.61	3028.32	48.9	215.9	12.8	221.4	21.8
0270003	Peace River Citrus Products	Desoto	409.8	3010.1	-100.9	197.7	333.0	221.9	85.8
1110010	Dickerson Florida, Inc.	St. Lucie	562.24	3030.36	51.6	217.9	13.3	223.9	83.4
1110107	Treasure Coast Land Clearing	St. Lucie	545.7	3035.2	35.0	222.8	8.9	225.5	15.0
0550018	Tampa Electric Company	Highlands	464.3	3035.4	-46.4	223.0	348.3	227.7	4,046
1110060	Florida Gas Transmission Company	St. Lucie	557.24	3035.78	46.6	223.3	11.8	228.1	10.6
1110003	Ft Pierce Utilities Authority	St. Lucie	566.12	3036.35	55.5	223.9	13.9	230.7	1,629
0550004	TECO-Sebring/Dinner Lake	Highlands	456.8	3042.5	-53.9	230.1	346.8	236.3	-1314
0550003	Florida Power Corp D/B/A Progress Energy I	Highlands	451.4	3050.5	-59.3	238.1	346.0	245.3	5,054
0490043	Vandolah Power Company, LLC	Hardee	408.75	3044.5	-101.9	232.1	336.3	253.4	221

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[a] The approximate center of the Everglades National Park is located at UTM Coordinates: East 510.7 km
North 2812.4 km

TABLE 6-6

PROJECT BUILDING DIMENSIONS USED IN THE FPL GLADES POWER PARK MODELING ANALYSIS

Stucture	Height ft	Height m	Length ft	Length m	Width ft	Width m
Boiler Unit No. 1 Structure	304	92.7	84	25.6	148	45.1
Boiler Unit No. 2 Structure	304	92.7	84	25.6	148	45.1
Absorber for Units 1 & 2	142	43.1	85	25.8	69	21.0
ESP for Units 1 & 2	107	32.6	246	75.0	120	36.6
SCR Structure for Units 1 & 2	207	63.1	124	37.8	73	22.3
Coal Silos/Tripper for Units 1 & 2	205	62.5	205	62.5	28	8.5
Wet ESP- Boiler Unit No. 1	75.5	23.0	176	53.7	60	18.3
Wet ESP- Boiler Unit No. 2	75.5	23.0	176	53.7	60	18.3
Cooling Tower- North	50	15.2	860	262.2	108	32.9
Cooling Tower- South	50	15.2	860	262.2	108	32.9
Railcar Area	40	12.2	151	46.0	51	15.5
Limestone Track Hopper	40	12.2	100	30.5	51	15.5
Crusher House	120	36.6	50	15.2	49	14.9
Coal Handling Maintenance Building	30	9.1	84	25.6	148	45.1
Coal Transfer House 1 & 2	90	27.4	40	12.2	35	10.7
Flyash Silo	95	29.0	245	74.7	50	15.2
Flyash Processing Facility	100	30.5	150	45.7	200	61.0

Note: ESP= electrostatic precipitator
SCR= selective catalytic reduction

TABLE 6-7
SUMMARY OF THE MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP PROPOSED BOILERS ONLY

Pollutant, Averaging Time, and Rank		100% Load Emission Rate [a] (lb/hr)	100% Load Predicted Concentration [c] (μg/m^3)	70% Load Emission Rate [a] (lb/hr)	70% Load Predicted Concentration [c] (μg/m^3)	40% Load Emission Rate [a] (lb/hr)	40% Load Predicted Concentration [c] (μg/m^3)
SO$_2$							
Annual, Highest		696	0.55	487	0.50	278	0.42
24-Hour, Highest		696	5.16	487	4.82	278	3.87
3-Hour, Highest		696	14.8	487	13.5	278	11.0
PM$_{10}$							
Annual, Highest		313	0.25	219	0.23	125	0.19
24-Hour, Highest		313	2.32	219	2.17	125	1.74
NO$_x$							
Annual, Highest		870	0.69	609	0.63	348	0.53
CO							
8-Hour, Highest		2,680	42.1	1,876	41.6	1,072	34.8
1-Hour, Highest		2,680	103.5	1,876	87.1	1,072	70.0
SAM							
Annual, Highest		69.6	0.055	48.7	0.050	27.8	0.042
24-Hour, Highest		69.6	0.52	48.7	0.48	27.8	0.39
3-Hour, Highest		69.6	1.48	48.7	1.35	27.8	1.10
HF							
Annual, Highest		3.75	0.0030	2.63	0.0027	1.50	0.0023
24-Hour, Highest		3.75	0.028	2.63	0.026	1.50	0.021
Based on:	Year	Modeled Rate	Modeled Impact [c]	Modeled Rate	Modeled Impact [c]	Modeled Rate	Modeled Impact [c]
Annual, Highest	2001	7.937	0.00629	7.937	0.00805	7.937	0.0118
	2002	7.937	0.00532	7.937	0.00692	7.937	0.0102
	2003	7.937	0.00624	7.937	0.00822	7.937	0.0121
	2004	7.937	0.00552	7.937	0.00699	7.937	0.0102
	2005	7.937	0.00569	7.937	0.00743	7.937	0.0103
24-Hour, Highest	2001	7.937	0.0500	7.937	0.0693	7.937	0.102
	2002	7.937	0.0504	7.937	0.0616	7.937	0.084
	2003	7.937	0.0588	7.937	0.0786	7.937	0.110
	2004	7.937	0.0479	7.937	0.0647	7.937	0.086
	2005	7.937	0.0466	7.937	0.0662	7.937	0.099
8-Hour, Highest	2001	7.937	0.106	7.937	0.141	7.937	0.195
	2002	7.937	0.107	7.937	0.146	7.937	0.213
	2003	7.937	0.105	7.937	0.140	7.937	0.207
	2004	7.937	0.118	7.937	0.152	7.937	0.202
	2005	7.937	0.125	7.937	0.176	7.937	0.257
3-Hour, Highest	2001	7.937	0.148	7.937	0.198	7.937	0.283
	2002	7.937	0.148	7.937	0.205	7.937	0.290
	2003	7.937	0.149	7.937	0.201	7.937	0.291
	2004	7.937	0.169	7.937	0.199	7.937	0.287
	2005	7.937	0.157	7.937	0.219	7.937	0.313
1-Hour, Highest	2001	7.937	0.255	7.937	0.301	7.937	0.358
	2002	7.937	0.250	7.937	0.325	7.937	0.423
	2003	7.937	0.215	7.937	0.280	7.937	0.419
	2004	7.937	0.307	7.937	0.369	7.937	0.519
	2005	7.937	0.248	7.937	0.319	7.937	0.453

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[a] Emission rate is for 2 units. PM$_{10}$ emissions is only filterable PM

[b] Predicted concentration is based on modeled concentration times the ratio of actual emission rate and modeled emission rate of 7.937 lb/hr (1 g/s).

[c] Modeled concentrations were predicted based on 7.937 lb/hr (1 g/s) emission rate for the 2 units with one combined stack and using AERMOD with five years of meteorological data from 2001 to 2005. The surface and upper air data were from the National Weather Service stations at Ft. Myers and Tampa, respectively.

TABLE 6-8
SUMMARY OF THE PSD CLASS II SIGNIFICANT IMPACT ANALYSIS FOR FGPP PROPOSED BOILERS AND PM MATERIAL HANDLING OPERATIONS

Pollutant, Averaging Time, and Rank	**Maximum Predicted Concentration (µg/m^3)**			**Significant Impact Level (µg/m^3)**
	100% Load	**70% Load**	**40% Load**	
PROPOSED BOILERS ONLY				
$\underline{SO_2}$				
Annual, Highest	0.55	0.50	0.42	1
24-Hour, Highest	5.16	4.82	3.87	5
3-Hour, Highest	14.84	13.46	10.98	25
$\underline{PM_{10}}$				
Annual, Highest	0.25	0.23	0.19	1
24-Hour, Highest	2.32	2.17	1.74	5
$\underline{NO_x}$				
Annual, Highest	0.69	0.63	0.53	1
<u>CO</u>				
8-Hour, Highest	42.1	41.6	34.8	500
1-Hour, Highest	103.5	87.1	70.0	2000
PROPOSED BOILERS AND PM MATERIAL HANDLING OPERATIONS				
$\underline{PM_{10}}$				
Annual, Highest	0.80	NM	NM	1
24-Hour, Highest	6.89	NM	NM	5

Note: NM= not modeled.

TABLE 6-9
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) 2001	2002	2003	EPA Class I Significant Impact Levels (ug/m^3)	PSD Class I Increment (ug/m^3)
Everglades NP						
SO_2	Annual	0.011	0.015	0.013	0.1	2
	24-Hour	0.42	0.39	0.36	0.2	5
	3-Hour	1.61	1.28	1.42	1.0	25
PM_{10}	Annual	0.004	0.006	0.005	0.2	4
	24-Hour	0.15	0.18	0.13	0.3	8
NO_2	Annual	0.007	0.007	0.008	0.1	2.5
Chassahowitzka NWA						
SO_2	Annual	0.007	0.010	0.007	0.1	2
	24-Hour	0.16	0.19	0.14	0.2	5
	3-Hour	0.62	0.69	0.47	1.0	25
PM_{10}	Annual	0.003	0.004	0.003	0.2	4
	24-Hour	0.068	0.079	0.059	0.3	8
NO_2	Annual	0.003	0.005	0.003	0.1	2.5

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model and 3 years of meteorological data, 2001 to 2003, developd by VISTAS.

TABLE 6-10
MAXIMUM PREDICTED 24-HOUR AVERAGE SO_2 AND PM_{10} IMPACTS FOR COMPARISON TO THE AAQS-SCREENING AND REFINED ANALYSES FOR FGPP

		Concentration (µg/m^3) [a]			Receptor Location			
Averaging Time and Rank	Analysis	Total	Modeled Sources	Background	UTM East (m)	UTM North (m)	Time Period (YYMMDDHH)	AAQS (µg/m^3)
SO_2- 24-Hour								
Highest, second-highest	Screening	38.1	14.5	24	486,173	2,970,973	1062724	260
		38.6	15.1	24	484,500	2,970,000	2050724	
		36.9	13.3	24	484,750	2,977,250	3111724	
		40.0	16.5	24	486,400	2,972,900	4101024	
		36.6	13.0	24	483,900	2,976,500	5050524	
	Refined	40.0	16.5	24	486,400	2,972,900	4101024	
PM_{10}- 24-Hour								
Highest, second-highest	Screening	42.7	4.73	38	486,080	2,973,514	1041524	150
		41.7	3.73	38	486,080	2,973,514	2121324	
		43.7	5.75	38	486,080	2,973,514	3102324	
		43.2	5.18	38	486,080	2,973,514	4040424	
		43.9	5.87	38	486,113	2,973,543	5052424	
	Refined	43.9	5.87	38	486,113	2,973,543	5052424	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Ft. Myers and Tampa, respectively.

TABLE 6-11

MAXIMUM PREDICTED 24-HOUR AVERAGE SO_2 AND PM_{10} IMPACTS FOR COMPARISON TO THE PSD CLASS II INCREMENTS SCREENING AND REFINED ANALYSES FOR FGPP

Averaging Time and Rank	Analysis	Concentration ($\mu g/m^3$) [a] Modeled Sources	Receptor Location UTM East (m)	Receptor Location UTM North (m)	Time Period (YYMMDDHH)	PSD Class II Increment ($\mu g/m^3$)
SO_2- 24-Hour						
Highest, second-highest	Screening	5.8	483,834	2,971,590	1091624	91
		6.1	484,500	2,970,000	2050724	
		5.9	486,170	2,970,678	3092124	
		6.8	484,848	2,975,198	4111224	
		6.1	480,683	2,972,956	5121724	
	Refined	6.8	484,848	2,975,198	4111224	
PM_{10}- 24-Hour						
Highest, second-highest	Screening	4.5	486,080	2,973,514	1041524	30
		3.6	486,080	2,973,514	2121324	
		5.7	486,080	2,973,514	3102324	
		5.1	486,080	2,973,514	4040424	
		5.6	486,113	2,973,543	5052424	
	Refined	5.7	486,080	2,973,514	3102324	

Note: YYMMDDHH = Year, Month, Day, Hour Ending.

[a] Concentrations are based on highest concentrations predicted using AERMOD with five years of meteorological data from 2001 to 2005 of surface and upper air data from the National Weather Service stations at Ft. Myers and Tampa, respectively.

TABLE 6-12

MAXIMUM SO_2 CONCENTRATIONS PREDICTED FOR COMPARISON TO THE PSD CLASS I INCREMENTS AT THE PSD CLASS I AREA OF THE EVERGLADES NP

Pollutant	Averaging Time	Maximum Predicted Concentration (ug/m^3) [a] 2001	2002	2003	PSD Class I Increment (ug/m^3)
Everglades NP					
SO_2	24-Hour	3.67	3.00	4.59	5
	3-Hour	8.05	8.42	9.66	25

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model and three years of meteorological data, 2001 to 2003, developd by VISTAS.

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts that FGPP will have on vegetation, soils, visibility, and direct growth, both in the vicinity of FGPP and at the PSD Class I areas of the Everglades NP and Chassahowitzka NWA.

7.1 IMPACTS DUE TO ASSOCIATED DIRECT GROWTH

7.1.1 INTRODUCTION

Rule 62-212.400(3)(h)(5), F.A.C., states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the construction and operation of FGPP. This information is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

The Site is located in Glades County, which is bounded by Okeechobee County to the north, Hendry County to south, and Charlotte County to the west. The total area of Glades County is 986 square miles; 774 square miles of land and 213 square miles of water.

FGPP is being constructed to meet current and projected electric demands. FPL has an obligation to meet this increase in electric demand. Additional growth as a direct result of the additional electric power provided by FGPP is not expected.

Construction of FGPP will occur over a 5-year period requiring an average of approximately 1,600 workers during that time. It is anticipated that many of these construction personnel will commute to the Site.

FGPP will employ a total of about 180 operational workers at plant build-out. The operational workforce will also include annual contracted maintenance workers to be hired for periodic routine services. The workforce needed to operate FGPP represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location of FGPP. The existing commercial and industrial infrastructure should be adequate to provide any support services that FGPP might require and would not increase with the operation of FGPP. The addition of the two units will have little effect on the increase or growth in the area.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Glades County. As such, the information presented is available from a variety of sources (i.e., Florida Statistical Abstract, FDEP, etc.) that characterize Glades County as a whole.

7.1.2 RESIDENTIAL GROWTH

Population and Household Trends

As an indicator of residential growth, the trend in the population and number of household units in Glades County since 1977 are shown in Figure 7-1. The County experienced a 79-percent increase in population for the years 1977 through 2004. During this period, there was an increase in population of about 11,000. Similarly, the number of households in the County increased by about 3,900, or 105 percent, since 1977.

Growth Associated with the Operation of FGPP

Because there will be about 180 employees needed to operate the FGPP, residential growth due to FGPP will be minimal.

7.1.3 COMMERCIAL GROWTH

Retail Trade and Wholesale Trade

As an indicator of commercial growth in Glades County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 7-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches, and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has decreased by 14 establishments and 90 employees, or 64 and 23 percent, respectively. For the same period, wholesale trade has increased by about 4 establishments and 24 employees, or 133 and 243 percent, respectively.

Labor Force

The trend in the labor force in Glades County since 1977 is shown in Figure 7-3. The greatest number of persons employed in Glades County has been in the cattle, fishing, sugar cane, produce, and citrus industries. Between 1977 and 2004, approximately 2,800 persons were added to the available work force, for an increase of 167 percent.

Tourism

Another indicator of commercial growth in Glades County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 7-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2004, there were slight increases of 11 and 57 percent in the number of hotels and motels as well as in the number of units at those facilities, respectively.

Transportation

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Glades County is presented in Figure 7-5.

The County's main artery is U.S. Highway 27.

Between 1977 and 2001, there was an increase of more than 200,000 VMT, or 58 percent, on major roadways in the County.

Growth Associated with the Operation of FGPP

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during operation of FGPP. The workforce needed to operate FGPP represents a small fraction of the labor force present in the immediate and surrounding areas.

7.1.4 INDUSTRIAL GROWTH

Manufacturing and Agricultural Industries

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Glades County since 1977 is shown in Figure 7-6. As shown, the manufacturing industry experienced an increase of 200 percent from 1977 through 2004.

As another indicator of industrial growth, the trend in the number of employees in the agricultural industry in Glades County since 1977 is also shown in Figure 7-6. As shown, the agricultural industry experienced a decrease in employment of 67 percent from 1977 through 2004.

Utilities

There are no existing power plants in Glades County. Glades Electric Cooperative distributes electricity to some areas within Glades County. The electric generation facilities that divide the electricity are located outside Glades County (e.g., Seminole Electric Coal Plant in Putnam County).

Growth Associated with the Operation of FGPP

Since the PSD baseline date of August 7, 1977, there have been only a few major facilities built within a 35-km radius of the Site. The nearest major sources are the Southern Gardens Citrus Processing Corporation's facility and the U.S. Sugar Corporation's Clewiston mill. There are a limited number of facilities located throughout the 50-km radius area surrounding FGPP. Based on the locations of nearby air emission sources, there has not been a concentration of industrial and commercial growth in the vicinity of FGPP.

7.1.5 AIR QUALITY DISCUSSION

Air Emissions of Nearby Sources

Based on actual emissions reported for 2001 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary and area sources in the County are as follows:

- SO_2: 130 TPY
- PM_{10}: 3,249 TPY
- NO_x: 1,035 TPY
- CO: 22,405 TPY
- VOC: 3,653 TPY

Air Emissions from Mobile Sources

The trends in the air emissions of CO, VOC, and NO_x from mobile sources in Glades County are presented in Figure 7-7. Between 1977 and 2005, there were significant decreases in these emissions. The decrease in CO, VOC, NO_x emissions were about 34, 3, and 1 tons per day (TPD), respectively, which represent decreases from 1977 emissions of 75, 78, and 43 percent, respectively.

Air Monitoring Data

Since 1977, Glades County has been classified as attainment or maintenance for all criteria pollutants. Although air quality monitoring data have not been collected in Glades County, air quality monitoring data collected at monitoring stations nearest to FGPP were used to assess air quality trends since 1977. Air quality monitoring data were based on the following monitoring stations:

- SO_2 concentrations - Riviera Beach, Palm Beach County; Sarasota; Sarasota County;
- PM_{10} concentrations - Belle Glade, Palm Beach County; Clewiston, Hendry County;
- NO_2 concentrations - West Palm Beach and Palm Beach, Palm Beach County;
- CO concentrations - West Palm Beach and Palm Beach, Palm Beach County; and
- O_3 concentrations - Royal Palm Beach, Palm Beach County.

Data collected from these stations are considered to be generally representative of air quality in Glades County. Because these monitoring stations are generally located in more industrialized areas than FGPP, the reported concentrations are likely to be somewhat higher than that experienced at the Site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable AAQS. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources, as well as the effects of meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than the monitored concentrations from these sites.

In addition, since 1988, PM in the form of PM_{10} has been collected at the air monitoring stations due to the promulgation of the PM_{10} AAQS. Prior to 1989, the AAQS for PM was in the form of TSP concentrations, and this form was measured at the stations.

SO_2 Concentrations

The trends in the annual, 24-hour, and 3-hour average SO_2 concentrations measured at the closest monitoring station near FGPP since 1977 are presented in Figures 7-8 through 7-10, respectively. These data are for a source-oriented site in Palm Beach County and conservative for FGPP. SO_2 concentrations have been measured at three stations for various time periods throughout these years. As shown in these figures, concentrations have been and continue to be well below the AAQS.

PM_{10}/TSP Concentrations

The trends in the annual and 24-hour average PM_{10} and TSP concentrations since 1977 for monitoring sites in Hendry and Palm Beach Counties are presented in Figures 7-11 and 7-12, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to PM_{10}.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988, when PM_{10} concentrations have been measured, the PM_{10} concentrations have been and continue to be below the AAQS.

NO_2 Concentrations

The trends in the annual average NO_2 concentrations measured at the nearest monitors to FGPP are presented in Figure 7-13. As shown in this figure, measured NO_2 concentrations at the nearest monitors have been well below the AAQS.

CO Concentrations

The trends in the 1- and 8-hour average CO concentrations since 1977 are presented in Figures 7-14 and 7-15, respectively. As shown in these figures, measured CO concentrations at the nearest monitors have been well below the AAQS.

Ozone Concentrations

The trends in the 1-hour average O_3 concentrations since 1977 are presented in Figure 7-16. The 8-hour average O_3 concentrations are presented in Figure 7-17. As shown in these figures, the measured O_3 concentrations have been well below the AAQS.

Air Quality Associated with the Operation of FGPP

The air quality data measured in the region of FGPP indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for FGPP are predicted to be low and, for certain pollutants, below the significant impact levels, the air quality concentrations in the region are expected to remain below and comply with the AAQS when FGPP becomes operational.

7.2 IMPACTS ON SOILS, VEGETATION, WILDLIFE, AND VISIBILITY IN FGPP VICINITY

The foundation for protecting the air quality including impacts to soils, vegetation and wildlife is the Ambient Air Quality Standards (AAQS) established under the federal Clean Air Act (CAA). The CAA clearly establishes the requirements of the AAQS as stated by EPA (2005): "*The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for wide-spread pollutants from numerous and diverse sources considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires periodic review of the science upon which the standards are based and the standards themselves.*" http://www.epa.gov/ttn/naaqs/ Florida has adopted both the Primary and Secondary NAAQS. For sulfur dioxide, the Florida AAQS are more stringent than the federal standards. In addition, Florida has adopted the PSD increments, which are much more stringent than the AAQS.

7.2.1 IMPACTS ON VEGETATION AND SOILS

Vegetative communities within FGPP vicinity have been significantly altered due to agricultural activities. The Site is dominated by sugar cane fields, with adjacent areas of improved pasture, live oak/cabbage palm hammock, and freshwater wetlands. Surrounding areas include additional sugar cane fields, improved pastures utilized for cattle grazing, a dairy operation, and areas of unimproved pasture, marshes, and forested wetlands associated with the Nicodemus Slough and Fisheating Creek. According to the Soil Survey of Glades County, Florida (USDA 2000), dominant soils on the Site include six series: Oldsmar sand, Immokalee sand, Boca fine sand, Pineda fine sand, Malabar fine sand, and Malabar fine sand, high. These soils are classified as Spodosols (Immokalee and Oldsmar series) and Alfisols (Boca, Pineda, and Malabar series). The Spodosol series are further classified within the Haplaquod great group, which has an average buffering capacity of 78,000 eq/ha (Florida Electric Power Coordinating Group, Inc.; 1986), while the Alfisol series are further classified within the Glossaqualf and Ochraqualf great groups, with average buffering capacities of 323,000 and 193,000 eq/ha, respectively. The extremely low emissions and inherent buffering capacity of these soils precludes any significant adverse impacts resulting from operation of FGPP.

Similarly, the vegetative communities surrounding the facility will not be adversely affected as a result of FGPP's emissions. Emissions will be maintained well below the AAQS, which are designed to protect human health, vegetation, and wildlife. The extremely low emissions will not produce any significant adverse impacts to the vegetation of the Nicodemus Slough or Fisheating Creek areas.

FGPP's impacts on the local air quality, together with the background sources, are predicted to be well below the AAQS. In addition, FGPP's VOC emissions represent an insignificant increase in regional VOC emissions. Since the AAQS are also designed to protect the public welfare, including effects on soils and vegetation, no detrimental effects on soils or vegetation should occur in this area due to FGGP's operation.

7.2.2 IMPACTS ON WILDLIFE

Although air pollution impacts to wildlife have been reported in the literature, many of the incidents involved acute exposures to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutants levels.

It is unlikely that FGPP's emissions will cause injury or death to wildlife based on a review of the available literature on air pollutant effects on wildlife. FGPP's impacts are predicted to be very low and dispersed over a large area. Coupled with the mobility of wildlife, the potential for exposure of wildlife to FGPP's impacts under weather conditions that lead to high concentrations is extremely unlikely.

7.2.3 IMPACTS ON VISIBILITY

No visibility impairment in FGPP's vicinity is expected due to the types and quantities of emissions proposed for FGPP. The combination of the fabric filter, wet FGD and WESP will reduce the opacity of the stacks. The primary visible plume that can be observed under normal operation will be a water vapor plume starting at the stack and dissipating downwind. The concentration level of pollutants will be at levels that extended visual plumes will not occur. For example, SAM will be controlled to a concentration of about 1 ppm in the exhaust gases. Visual SAM plumes typically only occur if the SAM concentrations exceed 5 to 10 ppm. Similarly, the PM levels will be at low concentrations due to the removal of PM in the fabric filter, wet FGD and WESP.

7.3 <u>IMPACTS TO PSD CLASS I AREAS</u>

7.3.1 IDENTIFICATION OF AQRVS AND METHODOLOGY

An AQRV analysis was conducted to assess the potential risk to AQRVs at the Everglades NP and Chassahowitzka NWA due to the emissions from FGPP. The Everglades NP is the closest Class I area to the Site, and is located 113 km south of the Site. The Chassahowitzka NWA is located about 240 km from the Site.

The U.S. Department of the Interior in 1978 administratively defined AQRVs to be:

> *All those values possessed by an area except those that are not affected by changes in air quality and include all those assets of an area whose vitality, significance, or integrity is dependent in some way upon the air environment. These values include*

> *visibility and those scenic, cultural, biological, and recreational resources of an area that are affected by air quality.*
>
> *Important attributes of an area are those values or assets that make an area significant as a national monument, preserve, or primitive area. They are the assets that are to be preserved if the area is to achieve the purposes for which it was set aside (Federal Register 1978).*

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the Everglades NP and bioindicators of air pollution (e.g., lichens) are also evaluated.

The maximum predicted atmospheric concentrations due to the increase in emissions resulting from FGPP at the Everglades NP and Chassahowitzka NWA are presented in Tables 7-1 and 7-2, respectively. As shown, the predicted increases in impacts are very low for all pollutants considered.

7.3.2 IMPACTS TO SOILS

For soils, the potential and hypothesized effects of atmospheric deposition include:

- Increased soil acidification,
- Alteration in cation exchange,
- Loss of base cations, and
- Mobilization of trace metals.

The potential sensitivity of specific soils to atmospheric inputs is related to two factors. First, the physical ability of a soil to conduct water vertically through the soil profile is important in influencing the interaction with deposition. Second, the ability of the soil to resist chemical changes, as measured in terms of pH and soil cation exchange capacity (CEC), is important in determining how a soil responds to atmospheric inputs.

Dominant soil series in the Everglades NP include the Lauderhill-Dania-Pahokee and Perrine-Biscayne-Pennusco associations of freshwater and sawgrass marshes, as well as the Matecumbe series found underneath hardwood hammocks. The Lauderhill-Dania-Pahokee series are poorly drained organic soils underlain by limestone found in areas of sawgrass, freshwater marshes, and ponds. The Perrine-Biscayne-Pennusco series are poorly drained soils consisting of marl, a limestone-rich clayey substrate. The Matecumbe series soils are moderately well drained, rapidly permeable, organic soils underlain by oolitic limestone bedrock, found under small tropical hardwood hammocks on the Miami Ridge and in the Everglades NP. These soils are generally classified as histosols (peat soils), which have a large organic matter content and have extremely high buffering capacities (average of 765,000 eq/ha) based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The direct connection of these soils with subsurface limestone tends to neutralize any acidic inputs. Moreover, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$). According to the National Park Service, there is no indication that soils in the Everglades NP are sensitive to deposition of air pollutants (NPS, 2006).

The Chassahowitzka NWA contains over 31,000 acres of saltwater bays, estuaries and brackish marshes. According to the U.S. Department of Agriculture (USDA) Soil Surveys of Citrus and Hernando Counties, nine soil complexes are found in the Chassahowitzka NWA. These include Aripeka fine sand, Aripeka-Okeelanta-Lauderhill, Hallendale-Rock outcrop, Homosassa mucky fine sandy loam, Lacooche, Okeelanta mucks, Okeelanta-Lauderdale-Terra Ceia mucks, Rock outcrop-Homosassa-Lacoochee, and Weekiwachee-Durbin mucks (Porter, 1996). The majority of the soil complexes found in the Chassahowitzka NWA are inundated by tidal waters, contain a relatively high organic matter content, and have high buffering capacities based on their CEC, base saturation, and bulk density. The regular flooding of these soils by the Gulf of Mexico regulates the pH and any change in acidity in the soil would be buffered by this activity. Therefore, they would be relatively insensitive to atmospheric inputs. However, Terra Ceia, Okeelanta, and Lauderdale freshwater mucks are present along the eastern border of the Chassahowitzka NWA, and may be more sensitive to atmospheric sulfur deposition (Porter, 1996). Although not tidally influenced, these freshwater mucks are highly organic and, therefore, have a relatively high intrinsic buffering capacity. The relatively low sensitivity of the soils to atmospheric inputs coupled with the extremely low ground-level pollutant concentrations resulting from FGPP at the Chassahowitzka NWA precludes any significant impact on soils.

The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants estimated from FGPP emissions at the Class I areas precludes any significant impact on soils.

7.3.3 IMPACTS TO VEGETATION

At the PSD Class I areas, the maximum concentrations from FGPP are predicted to be low, well below the National and Florida AAQS, and are not expected to result in any adverse impacts to soils or vegetation. To ensure avoidance of adverse impacts, maximum modeled emissions from FGPP were compared to pollutant concentrations that have demonstrated deleterious effects to sensitive species of vegetation.

In general, the effects of air pollutants on vegetation occur primarily from SO_2, NO_2, O_3, and PM. Effects from other air contaminants, such as fluoride, chlorine, hydrogen chloride, ethylene, ammonia, hydrogen sulfide, CO, and pesticides, have also been reported in the literature. The effects of air pollutants are dependent both on the concentration of the contaminant and the duration of the exposure. The term "injury," as opposed to damage, is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. Air contaminants are thought to interact primarily with plant foliage, which is considered to be the major pathway of exposure. For purposes of this analysis, it was assumed that 100 percent of each air contaminant of concern is accessible to the plants.

Injury to vegetation from exposure to various levels or air contaminants can be termed acute, physiological, or chronic. Acute injury occurs as a result of a short-term exposure to a high contaminant concentration and is typically manifested by visible injury symptoms ranging from chlorosis (discoloration) to necrosis (dead areas). Physiological or latent injury occurs as the result of a long-term exposure to contaminant concentrations below that which results in acute injury symptoms. Chronic injury results from repeated exposure to low concentrations over extended periods of time, often without any visible symptoms, but with some effect on the overall growth and productivity of the plant. In this assessment, 100 percent of the particular air pollutant in the ambient air was assumed to interact with the vegetation, which is a very conservative approach.

The concentrations of the pollutants, duration of exposure, and frequency of exposures influence the response of vegetation to atmospheric pollutants. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentrations, which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term, higher doses. A dose is the product of the concentration of the pollutant and duration of the exposure.

Sulfur Dioxide

Sulfur is an essential plant nutrient usually taken up as sulfate ions by the roots from the soil solution. When sulfur dioxide in the atmosphere enters the foliage through pores in the leaves, it reacts with water in the leaf interior to form sulfite ions. Sulfite ions are highly toxic. They interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, within the leaf, sulfite is oxidized to sulfate ions, which can then be used by the plant as a nutrient. Small amounts of sulfite may be oxidized before they prove harmful.

Observed SO_2 effect levels for several plant species and plant sensitivity groupings are presented in Tables 7-3 and 7-4, respectively. SO_2 gas at elevated levels has long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercoastal necrotic areas that appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Background levels of SO_2 range from 2.5 to 25 $\mu g/m^3$.

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour average SO_2 concentrations of 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour average SO_2 concentrations of 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress (*Taxodium* sp.), slash pine (*Pinus elliottii*), live oak (*Quercus virginiana*), and mangrove (*Avicennia* sp., *Laguncularia* sp., and *Rhizophora* sp.) exposed to 1,300 µg/m^3 SO_2 for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant was visibly injured at 3-hour average SO_2 concentrations of 920 µg/m^3. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 µg/m^3 for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 µg/m^3 SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

Species of lichens, which are symbiotic organisms comprised of green or blue-green algae and fungi, have been used worldwide as air pollution monitors because relatively low levels of sulfur, nitrogen, and fluorine-containing pollutants adversely affect many species, altering lichen community composition, growth rates, reproduction, physiology, and morphological appearance (Blett *et al.*, 2003). SO_2 is considered to be the primary factor causing the death of lichens in most urban and industrial areas. The first indications of damage from SO_2 include the inhibition of nitrogen fixation, increased electrolyte leakage, and decreased photosynthesis and respiration followed by discoloration and death of the algal component of the lichen (Fields 1988). Sensitive species are damaged or killed by annual average levels of sulfur dioxide concentrations ranging from 8 to 30 µg/m^3, and very few lichens can tolerate levels exceeding 125 µg/m^3 (Johnson, 1979; DeWit, 1976; Hawsworth and Rose, 1970; LeBlanc *et al.*, 1972).

The maximum 3-, 8-, and 24-hour average SO_2 concentrations for FGPP are predicted to be 1.6, 0.8, and 0.4 µg/m^3, respectively, at the Everglades NP Class I area. The maximum SO_2 concentrations for FGPP predicted at the Chassahowitzka NWA are approximately 50 percent or lower than those predicted at the Everglades NP. These values are less than 1 percent of the concentrations that caused acute effects in sensitive species of vegetation (i.e., 790 µg/m^3). The maximum annual average SO_2 concentrations for FGPP predicted within the Everglades NP and Chassahowitzka NWA are 0.015 and 0.010 µg/m^3, respectively. These values are less than 0.2 percent of those that caused chronic effects to the most sensitive species of lichens. The modeled annual incremental increase in SO_2 adds only slightly to background levels of this gas and poses no threat to area vegetation.

Nitrogen Dioxide

NO_2 can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru *et al.*, 1979).

Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short term exposure to NO_2 at concentrations of 564 $\mu g/m^3$ caused adverse effects in lichen species (Holopainen and Karenlampi 1984), while for vascular plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979).

The maximum 1-, 3-, and 8-hour average NO_2 concentrations due to FGPP are predicted to be 2.50, 1.72, and 0.91 $\mu g/m^3$, respectively, at the Everglades NP Class I area. Similarly to the SO_2 impacts, the maximum NO_2 concentrations for FGPP predicted at the Chassahowitzka NWA are less than those predicted at the Everglades NP. These maximum concentrations are over three orders of magnitude lower than the levels that could potentially injure 5 percent of vascular plant foliage (i.e., 3,800 to 15,000 $\mu g/m^3$), and less than 0.5 percent of the concentration that caused acute adverse effects in sensitive lichen species. For a chronic exposure, the maximum annual NO_2 concentration due to FGPP is predicted to be 0.0075 $\mu g/m^3$ at the Everglades NP, which is over six orders of magnitude lower than the level that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 $\mu g/m^3$).

Although it has been shown that simultaneous exposure to SO_2 and NO_2 results in synergistic plant injury (Ashenden and Williams, 1980), the magnitude of this response is generally only 3 to 4 times greater than either gas alone and usually occurs at unnaturally high levels of each gas. Therefore, the concentrations within the Everglades NP and Chassahowitzka NWA are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

Particulate Matter

Although information pertaining to the effects of PM on plants is scarce, baseline concentrations are available (Mandoli and Dubey, 1988). Ten species of native Indian plants were exposed to levels of PM that ranged from 210 to 366 $\mu g/m^3$ for an 8-hour averaging period. Damage in the form of a higher leaf area/dry weight ratio was observed at varying degrees for most plants tested. Concentrations of PM lower than 163 $\mu g/m^3$ did not appear to be injurious to the tested plants.

The maximum 8-hour PM concentration due to FGPP at the Everglades NP is predicted to be 0.35 $\mu g/m^3$. This concentration is less than 0.2 percent of the values that affected plant foliage (i.e., 210 $\mu g/m^3$). The maximum concentration predicted at the Chassahowitzka NWA (0.17 $\mu g/m^3$) is less than 0.1 percent of the values that affected plant foliage. As a result, no significant effects to vegetative AQRVs are expected from FGPP's emissions of particulate matter.

Carbon Monoxide

As with PM, information pertaining to the effects of CO on plants is scarce. The main effect of high concentrations of CO is the inhibition of cytochrome *c* oxidase, the terminal oxidase in the mitochondrial electron transfer chain. Inhibition of cytochrome *c* oxidase depletes the supply of adenosine triphosphate (ATP), the principal donor of free energy required for cell functions. However, this inhibition only occurs at extremely high concentrations of CO. Pollok *et al.* (1989) reported that exposure to $CO:O_2$ ratio of 25 (equivalent to an ambient CO concentration of 6.85×10^6 $\mu g/m^3$) resulted in stomatal closure in the leaves of the sunflower (*Helianthus annuus*). Naik *et al.* (1992) reported cytochrome *c* oxidase inhibition in corn, sorghum, millet, and Guinea grass at $CO:O_2$ ratios of 2.5 (equivalent to an ambient CO concentration of 6.85×10^5 $\mu g/m^3$). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum 1-hour average concentration due to FGPP is 11.3 $\mu g/m^3$ in the Everglades NP Class I area, which is less than 0.002 percent of the minimum value that caused inhibition in laboratory studies (i.e., 6.85×10^5 $\mu g/m^3$). The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum predicted annual concentration of 0.10 $\mu g/m^3$ reflects a more realistic, yet conservative, CO level for the Class I area. This maximum concentration is predicted to be less than 0.0001 percent, less than the value that caused cytochrome *c* oxidase inhibition.

Sulfuric Acid Mist

Acidic precipitation or acid rain is coupled to SO_2 emissions mainly formed during the burning of fossil fuels. This pollutant is oxidized in the atmosphere and dissolves in rain forming SAM, which falls as acidic precipitation (Ravera, 1989). Although concentration data are not available, SAM has been reported to yield necrotic spotting on the upper surfaces of leaves (Middleton *et al.*, 1950).

No significant adverse effects on vegetation are expected from FGPP's emissions because SO_2 concentrations, which lead directly to the formation of SAM concentrations, are predicted to be well below levels that have been documented as negatively affecting vegetation. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentrations of aluminum in the soil water (Goldstein *et al.*, 1985).

Hydrogen Fluoride

Exposure of sensitive plant species to 0.5 $\mu g/m^3$ of fluorides for 30 days has resulted in significant foliar necrosis (EPA, 1990). The maximum annual average concentrations of hydrogen fluoride in the PSD Class I areas resulting from FGPP are 0.00014 $\mu g/m^3$ and 0.00013 $\mu g/m^3$ for the Everglades NP and Chassahowitzka NWA, respectively, which are less than 0.03 percent of the concentration that caused foliar necrosis in sensitive species of vegetation. Due to the extremely low hydrogen fluoride emission rates, FGPP will not result in adverse impacts to vegetation in the vicinity of FGPP or within the PSD Class I areas.

VOC Emissions and Impacts to Ozone

VOC and NO_x emissions are precursors to the formation of O_3. Ozone, although not directly emitted as a result of FGPP, is formed when nitrogen oxides and volatile organics react in the atmosphere in the presence of sunlight. Natural (i.e., without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975). O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

The nearest monitor to FGPP that measures O_3 concentrations is located in Highland County (see Table 5-1). This station measures concentrations according to EPA procedures. Based on the O_3 monitoring concentrations measured over the last several years, the region is in attainment of the existing 1-hour O_3 AAQS as well as the new 8-hour O_3 AAQS.

Ozone has been continuously monitored at Everglades NP since 1986 (Site #120250030). The data indicate no exceedances of the 1-hour human health-based primary National Ambient Air Quality Standard, or any calculated exceedances of the new 8-hour primary NAAQS. Ozone sensitive vegetation is present within the Everglades NP and Chassahowitzka NWA, including elderberry (*Sambucus canadensis*), smooth cordgrass (*Spartina alterniflora*), and Virginia creeper (*Parthenocissus quinquefolia*) (NPS, 2003).

Elderberry is considered a bioindicator for describing ozone impact thresholds. However, the low levels of ozone exposure at the Class I Areas make the risk of foliar ozone injury to plants low (NPS, 2004). Exposure indices, including the Sum06 and W126 indices, utilize maximum hourly concentrations to identify risk assessment thresholds. In the case of the Everglades NP, exposures above 80 ppb were uncommon, and concentrations never reached 100 ppb, which are the levels of exposure that are associated with the production of foliar injury (NPS, 2004). FGPP's influence on O_3 concentrations is negligible and will not result in any foliar damage resulting from increases in O_3 concentrations.

Total VOC emissions in the region (i.e., Glades, Hendry, Martin, and Palm Beach Counties) are approximately 89,100 TPY for stationary and mobile sources (based on AIRSdata website by EPA for 2001, the latest year of available data). The maximum VOC emissions increase due to FGPP is 260 TPY, which represents less than a 0.3-percent increase in regional VOC emissions. Therefore, the effects of O_3, as a result of VOC emissions from FGPP, are expected to be insignificant.

Summary

In summary, the phytotoxic effects on the Everglades NP and Chassahowitzka NWA from FGPP's emissions are expected to be minimal. It is important to note that the substances were evaluated with the assumption that 100 percent was available for plant uptake. This is rarely the case, is ever, in a natural ecosystem.

7.3.4 IMPACTS TO WILDLIFE

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1981; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary AAQS. Physiological and behavioral effects have been observed in experimental animals at or below these standards. No observable effects to fauna are expected at concentrations below the values reported in Table 7-5.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the National AAQS. This occurs in non-attainment areas, e.g., Los Angeles Basin. Risks to wildlife also may occur for wildlife living in the vicinity of an emission source that experiences frequent upsets or episodic conditions resulting from malfunctioning equipment, unique meteorological conditions, or startup operations (Newman and Schreiber, 1988). Under these conditions, chronic effects (e.g., particulate contamination) and acute effects (e.g., injury to health) have been observed (Newman, 1981).

For impacts on wildlife, the lowest threshold values of SO_2, NO_x, and particulates that are reported to cause physiological changes are shown in Table 7-5. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area.

Studies have demonstrated damage to the tracheal epithelium of bird species (Llacuna *et. al.*, 1993). These adverse effects occurred at very high concentrations of SO_2 (maximum of 2,500 $\mu g/m^3$) and NO_x (maximum of 1,221 $\mu g/m^3$), several orders of magnitude greater when compared to the potential impacts from FGPP. Impacts to avian species are typically related to reduction of food availability resulting from impacts to vegetation and herbivorous insects. FGPP's pollution control systems will result in extremely low emissions, far below the AAQS, and no significant adverse impacts to vegetation or the insects which feed upon vegetation in the vicinity of FGPP will occur. Therefore, no adverse air quality impacts to avian species resulting from reduced insect populations or vegetative production are anticipated.

No effects on wildlife AQRVs from SO_2, NO_x, and particulates are expected. These results are considered indications of the risk of other air pollutant emissions predicted from the FGPP, which is also considered to be negligible.

7.4 IMPACTS ON VISIBILITY AND FROM DEPOSITION

7.4.1 VISIBILITY

Visibility is an AQRV for the Everglades NP and Chassahowitzka NWA. Because both Class I areas are located more than 100 km from the Site, the change in visibility for FGPP was analyzed using the CALPUFF modeling system identified in Section 6.0.

Background

Based on the FLAG document, current regional haze guidelines characterize a change in visibility by the change in the light-extinction coefficient (b_{ext}). The b_{ext} is the attenuation of light per unit distance due to the scattering and absorption by gases and particles in the atmosphere. A change in the extinction coefficient produces a perceived visual change. An index that simply quantifies the percent change in visibility due to the operation of a source is calculated as:

$$\Delta\% = (b_{exts} / b_{extb}) \times 100$$

where: b_{exts} is the extinction coefficient calculated for the source, and
b_{extb} is the background extinction coefficient.

The purpose of the visibility analysis is to calculate the extinction at each receptor for each day of the year due to FGPP.

Processing of visibility impairment for FGPP was performed with the CALPUFF model, the CALPUFF post-processing program CALPOST, and the recently developed CALPOST-IMPROVE Processor. The analysis was conducted in accordance with the most recent guidance from the FLAG report (December 2000) and the Interagency Monitoring of Protected Visual Environments (IMPROVE) Steering Committee's latest recommendations. The CALPUFF postprocessor model CALPOST is used to calculate the combined visibility effects from the different pollutants that are emitted from FGPP. Daily background extinction coefficients are calculated on an hour-by-hour basis using relative humidity data from CALMET and hygroscopic and non-hygroscopic extinction components specified in the FLAG document. For the Class I area evaluated, the hygroscopic and non-hygroscopic components are 0.9 and 8.5 inverse mega meter (Mm^{-1}). CALPOST then predicts the percent change in light extinction for each day of the year using the IMPROVE algorithm. Visibility impacts determined are based on using hourly relative humidity (RH) observations and maximum RH capped at 95 percent. The CALPOST-IMPROVE Processor uses the CALPOST results and re-calculates the percent change in light extinction based on the revised IMPROVE algorithm. This procedure of analysis is known as Method 2.

CALPOST calculates visibility effects due to particulate matter from CALPUFF-modeled particulate matter component concentrations using a previously adopted IMPROVE algorithm. This initial algorithm was adopted by the EPA under the 1999 Regional Haze Rule. This previous algorithm assumes that light absorption by gases is zero, Rayleigh scattering is 10 Mm^{-1} for each monitoring site regardless of site elevation and meteorological condition, and particle scattering and absorption can be estimated by multiplying the concentrations of each of six major components by typical component-specific light extinction efficiencies. The initial IMPROVE algorithm elicited numerous technical concerns.

As a result of these concerns, the IMPROVE Steering Committee commissioned the development of a new IMPROVE algorithm for estimating light extinction from particulate matter component concentrations, which they adopted for use in December 2005. This updated algorithm resolves a number of the technical concerns between measured visibility and that calculated from particulate matter component concentrations.

The new IMPROVE equation was released by IMPROVE Steering Committee in the form of an Excel workbook, known as the CALPOST-IMPROVE Processor in November 2006. The new IMPROVE algorithm splits the total sulfate, nitrate, and organic carbon compound concentrations into two fractions, representing small and large size distributions of those compounds. New terms added to the algorithm are light absorption by NO_2 gas and light scattering due to fine sea salt accompanied by its own hygroscopic scattering enhancement factor. The new algorithm also uses Class I area specific Rayleigh scattering values rounded off to the nearest whole number and offers refinements to the deficiencies of the current algorithm and is as consistent as possible with the current scientific literature.

An alternative approach to assess visibility impairment has been recommended by the FLM and EPA for sources that are affected by the Best Achievable Retrofit Technology (BART) regulations. This approach, commonly known as the BART approach, estimates visibility impacts using Class I area specific monthly RH adjustment factors (referred to as Method 6). In the Method 6, the 8th highest daily average visibility impairments is determined for each year for the purpose of comparing the results to whether the source contributes to or causes visibility impairment. The 8th highest daily average visibility impairment, which corresponds to the 98-percentile daily value during 1 year, is recommended by the FLM and EPA to account for the frequency of the contributions to visibility impairment caused by the source based on the natural variability of meteorology (70 FR 39121).

The visibility analyses do not account for periods when naturally visibility impairment is occurring. In other words, the visibility impacts ignore periods where natural visibility conditions are already obscuring visibility, such as rain, fog, etc. If these periods are included, then unrealistically high visibility impacts are produced. As a result, additional analyses should be performed to evaluate those days when natural visibility impairment occurs, and exclude days where visibility impairment is caused by natural phenomena.

Methods

The visibility impact analysis for FGPP was performed using Method 6 and Method 2 with the new IMPROVE equation. Together, these analyses represent the latest methods for evaluating visibility and provide a conservative estimate of FGPP visibility impacts on Everglades NP and Chassahowitzka NWA PSD Class I Areas. Visibility analysis for the initial IMPROVE equation was also performed as requested by the NPS staff.

The results of Method 2 for days over 5 percent predicted visibility impairment were evaluated for periods when naturally occurring visibility impairment was occurring. This is referred to as Method 2 with natural obscuration adjustment. For the Everglades NP, the weather data from Miami and Fort Myers airports were reviewed for each of these days for occurrences of existing visibility-obscuring phenomenon (e.g., fog) and precipitation. The background light extinction was re-calculated using Method 2 for the hours when no visibility-obscuring weather phenomenon or precipitation were observed (unobstructed conditions) and using observed visibility range for the hours when weather phenomenon or precipitation were observed. Finally, the daily average light extinction was re-calculated based on the revised hourly background light extinction and a revised visibility percent change was determined by dividing the model daily average light extinction by the daily average background light extinction.

Results

The results of the regional haze analysis for FGPP were assessed using Method 6 and Method 2 with the new IMPROVE algorithm (see Tables 7-6 and 7-7). Method 2 with the initial IMPROVE algorithm is presented in Table 7-8.

Results of the visibility impairment for FGPP with Method 6 are presented in Table 7-6. As shown in Table 7-6, the 8th highest value at the Everglades NP due to FGPP is 4.1. Based on the 8th highest value predicted for FGPP in each year, there are no days during which the regional haze impacts were predicted above the 5-percent. For the Chassahowitzka NWA, the 8th highest value due to FGPP is 3.2. Based on the 8th highest value predicted for FGPP in each year, there are no days during which the regional haze impacts were predicted above 5-percent. It should be noted that in Method 6, days with naturally visibility impairment are not excluded in the analysis. Rather, the monthly relatively humidity and the frequency of visibility impairment (i.e., use of the 98th percentile, equivalent to the 8th highest daily average value) is used as a way to more realistically assess visibility impairment as recognized by EPA (70 FR 39121).

The maximum impact on visibility at the Everglades NP using Method 2 with the new IMPROVE equation (see Table 7-7) is predicted to be 8.11 percent with a total of 6 days out of 3 years above the 5-percent when days with naturally occurring visibility impairment are excluded. For the Chassahowitzka NWA, this method predicts only 1 day out of 3 years above 5 percent (i.e., 5.3 percent). When all days are considered in the analysis, including days when naturally occurring visibility occurs, the maximum impact on visibility at the Everglades NP is predicted to be 9.96 percent with a total of 10 days above 5-percent and at Chassahowitzka NWA is predicted to be 8.1 percent with a total of 5 days above 5-percent.

For completeness, the maximum impacts on visibility with Method 2 with the initial IMPROVE equation are shown in Table 7-8. The maximum impacts from the FGPP are predicted to be greater than 5-percent at the Everglades NP for less than 0.5 percent of the time (i.e., 6 days) over the 3-year period. At the Chassahowitzka NWA, the maximum impacts from the FGPP are predicted to be greater than the 5-percent for less than 0.1 percent of the time (i.e., 1 day) over the 3-year period.

Based on the analysis demonstrating infrequent occurrences of regional haze impacts from FGPP under all three modeling methods, it is concluded that FGPP will not have an adverse impact on visibility at either the Everglades NP or the Chassahowitzka NWA.

7.4.2 SULFUR AND NITROGEN DEPOSITION

General Methods

As part of the AQRV analyses, total nitrogen (N) and sulfur (S) deposition rates were predicted at the Everglades NP and Chassahowitzka Class I areas. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen or sulfur. The CALPUFF model is used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

For S deposition, the species include:

- SO_2, wet and dry deposition; and
- SO_4, wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N or S deposition in kg/ha, respectively, by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II Report, Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (USFWS) (January 2002). A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a new or modified source are considered insignificant. The maximum N and S depositions predicted for the FGPP are, therefore, compared to these DAT or significant impact levels.

Results

The maximum predicted N and S depositions predicted for FGPP in the PSD Class I areas of the Everglades NP and Chassahowitzka NWA are summarized in Table 7-9. The maximum N and S deposition rates for FGPP at the Everglades NP are predicted to be 0.009 and 0.020 kg/ha/yr, respectively. The maximum N and S deposition rates for FGPP at the Chassahowitzka NWA are predicted to be 0.009 and 0.018 kg/ha/yr, respectively. These maximum deposition rates are below the N significant impact level of 0.01 kg/ha/yr but above the S significant impact level of 0.01 kg/ha/yr.

The dominant soils of the Everglades NP and Chassahowitzka NWA include organic histosols with extremely high buffering capacities and sandy entisols overlying limestone, which provide a buffer to acidic inputs. These soils are resistant to acidic atmospheric inputs. The averaging buffering capacity of histosols is 765,000 equivalents/hectare (eq/ha) (FADS, 1986). As acid inputs (e.g., HNO_3^{-1} and $H_2SO_4^{-2}$), the maximum predicted deposition rates of 0.012 kg/ha/yr for N and 0.029 kg/ha/yr for S are 0.71 and 1.23 eq/ha/yr, respectively.

These deposition rates are extremely small compared to the buffering capacity of the soils in both Class I areas. These deposition rates are also small compared to the observed sulfur and nitrogen deposition obtained from the FADS. Measurements taken near the northern boundary of the Everglades NP (near U.S. Highway 41 and the boundary of Miami-Dade and Monroe Counties) found wet and dry deposition rates of 243 and 306 eq/ha/yr, respectively, over a 3-year period (FADS, 1986). In addition, the groundwater table is highly buffered due to the interaction with subsurface limestone formations, which results in high alkalinity (as $CaCO_3$). The relatively low sensitivity of the soils to acid inputs coupled with the extremely low ground-level concentrations of contaminants projected for the Class I areas from FGPP emissions precludes any significant impact on soils. Similarly, the total annual S and N deposition rates predicted for FGPP at the Class I areas are not expected to alter soil and/or groundwater pH that may result in adverse effects on vegetation.

TABLE 7-1
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP AT THE PSD CLASS I AREA OF THE EVERGLADES NP FOR THE AQRV ANALYSIS

		Maximum Predicted Concentration ($\mu g/m^3$)[a]		
Pollutant	**Averaging Time**	**2001**	**2002**	**2003**
Everglades NP				
SO_2	Annual	0.011	0.015	0.013
	24-Hour	0.42	0.39	0.36
	8-Hour	0.69	0.83	0.79
	3-Hour	1.61	1.28	1.42
	1-Hour	2.30	1.41	2.72
PM_{10}	Annual	0.0044	0.0061	0.0054
	24-Hour	0.15	0.18	0.13
	8-Hour	0.23	0.35	0.29
	3-Hour	0.56	0.52	0.51
	1-Hour	0.81	0.57	0.98
NO_2	Annual	0.0069	0.0073	0.0075
	24-Hour	0.34	0.24	0.30
	8-Hour	0.58	0.58	0.91
	3-Hour	1.72	1.11	1.19
	1-Hour	2.50	1.43	1.55
CO	Annual	0.073	0.10	0.08
	24-Hour	2.12	2.36	1.61
	8-Hour	3.16	4.20	3.62
	3-Hour	6.94	6.26	6.13
	1-Hour	9.72	6.80	11.33
SAM	Annual	0.0037	0.0055	0.0043
	24-Hour	0.08	0.20	0.08
	8-Hour	0.15	0.31	0.17
	3-Hour	0.25	0.41	0.27
	1-Hour	0.38	0.46	0.46
HF	Annual	0.00010	0.00014	0.00011
	24-Hour	0.0030	0.0033	0.0022
	8-Hour	0.0044	0.0059	0.0051
	3-Hour	0.0097	0.0088	0.0086
	1-Hour	0.0136	0.0095	0.0159

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model and three years of meteorological data, 2001 to 2003, developd by VISTAS.

TABLE 7-2
MAXIMUM CONCENTRATIONS PREDICTED FOR FGPP
HE PSD CLASS I AREA OF THE CHASSAHOWITZKA NWA FOR THE AQRV ANA

Pollutant	Averaging Time	Maximum Predicted Concentration (μg/m^3)[a]		
		2001	2002	2003
Chassahowitzka NWA				
SO_2	Annual	0.007	0.010	0.007
	24-Hour	0.16	0.19	0.14
	8-Hour	0.37	0.45	0.27
	3-Hour	0.62	0.69	0.47
	1-Hour	0.77	1.29	0.86
PM_{10}	Annual	0.0027	0.0044	0.0029
	24-Hour	0.07	0.08	0.06
	8-Hour	0.17	0.15	0.13
	3-Hour	0.23	0.27	0.22
	1-Hour	0.28	0.50	0.31
NO_2	Annual	0.0031	0.0047	0.0029
	24-Hour	0.14	0.10	0.08
	8-Hour	0.35	0.29	0.24
	3-Hour	0.63	0.74	0.48
	1-Hour	0.80	1.39	0.91
CO	Annual	0.073	0.09	0.08
	24-Hour	1.44	1.40	1.09
	8-Hour	2.46	2.92	2.05
	3-Hour	2.97	3.42	3.02
	1-Hour	3.20	6.03	3.83
SAM	Annual	0.003	0.0048	0.0033
	24-Hour	0.07	0.09	0.07
	8-Hour	0.16	0.18	0.14
	3-Hour	0.20	0.20	0.20
	1-Hour	0.21	0.21	0.22
HF	Annual	0.00010	0.00013	0.00011
	24-Hour	0.0020	0.0020	0.0015
	8-Hour	0.0034	0.0041	0.0029
	3-Hour	0.0042	0.0048	0.0042
	1-Hour	0.0045	0.0084	0.0054

[a] Concentrations are based on highest concentrations predicted using the CALPUFF model and three years of meteorological data, 2001 to 2003, developd by VISTAS.

TABLE 7-3

SO_2 EFFECTS LEVELS FOR VARIOUS PLANT SPECIES

Plant Species	Observed Effect Level (μg/m^3)	Exposure (Time)	Reference
Sensitive to tolerant	920 (20 percent displayed visible injury)	3 hours	McLaughlin and Lee, 1974
Lichens	200-400	6 hr/wk for 10 weeks	Hart *et al.*, 1988
Cypress, slash pine, live oak, mangrove	1,300	8 hours	Woltz and Howe, 1981
Jack pine seedlings	470-520	24 hours	Malhotra and Kahn, 1978
Black oak	1,310	Continuously for 1 week	Carlson, 1979

TABLE 7-4

SENSITIVITY GROUPINGS OF VEGETATION BASED ON VISIBLE INJURY AT DIFFERENT SO_2 EXPOSURES[a]

Sensitivity Grouping	SO_2 Concentration 1-Hour	SO_2 Concentration 3-Hour	Plants
Sensitive	1,310 - 2,620 µG/m^3	790 - 1,570 µG/m^3	Ragweeds
	(0.5 - 1.0 ppm)	(0.3 - 0.6 ppm)	Legumes
			Blackberry
			Southern pines
			Red and black oaks
			White ash
			Sumacs
Intermediate	2,620 - 5,240 µG/m^3	1,570 - 2,100 µG/m^3	Maples
	(1.0 - 2.0 ppm)	(0.6 - 0.8 ppm)	Locust
			Sweetgum
			Cherry
			Elms
			Tuliptree
			Many crop and garden species
Resistant	>5,240 µG/m^3	>2,100 µG/m^3	White oaks
	(>2.0 ppm)	(>0.8 ppm)	Potato
			Upland cotton
			Corn
			Dogwood
			Peach

[a] Based on observations over a 20-year period of visible injury occurring on over 120 species growing in the vicinities of coal-fired power plants in the southeastern United States.

Source: EPA, 1982a.

TABLE 7-5

EXAMPLES OF REPORTED EFFECTS OF AIR POLLUTANTS AT CONCENTRATIONS BELOW NATIONAL SECONDARY AMBIENT AIR QUALITY STANDARDS

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[a]	Respiratory stress in guinea pigs	427 to 854	1 hour
	Respiratory stress in rats	267	7 hours/day; 5 day/week for 10 weeks
	Decreased abundance in deer mice	13 to 157	continually for 5 months
Nitrogen Dioxide[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	Respiratory stress, reduced respiratory disease defenses	120 PbO_3	continually for 2 months
	Decreased respiratory disease defenses in rats, same with hamsters	100 $NiCl_2$	2 hours

Sources:
[a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak et al., 1977.

TABLE 7-6
MAXIMUM AVERAGE VISIBILITY IMPAIRMENT PREDICTED FOR THE FPL GLADES POWER PARK AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA (METHOD 6)

		Method 6 [a] (BART)			
Meteorological Data	**Parameter**	**2001**	**2002**	**2003**	**MAX/ TOTAL**
Everglades NP					
All Days	8th Highest	**3.4**	**4.1**	**3.9**	**4.1**
	Maximum %	6.6	10.5	5.1	10.5
	# Days > 5%	1	4	3	8
	# Days > 10%	0	1	0	1
Chassahowitzka NWA					
All Days	8th Highest	**2.06**	**3.2**	**1.8**	**3.2**
	Maximum	5.1	6.8	4.3	6.8
	# Days > 5%	1	4	0	5
	# Days > 10%	0	0	0	0

[a] Method 6 utilizes the 98th percentile impact or the 8th highest impact in any year to determine whether a source contributes to or causes visibility impairment.

Light extinction calculated using Method 6, which is based on Class I area specific monthly relative humidity factors.

TABLE 7-7
MAXIMUM AVERAGE VISIBILITY IMPAIRMENT PREDICTED FOR THE FPL GLADES POWER PARK AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA (METHOD 2 NEW IMPROVE EQUATION)

		Method 2 (New IMPROVE Equation [a])			
Meteorological Data	**Parameter**	**2001**	**2002**	**2003**	**MAX/ TOTAL**
Everglades NP					
All Days except those with natural visibility impairment	Maximum	**4.02**	**7.78**	**8.11**	**8.11**
	# Days > 5%	0	3	3	6
	# Days > 10%	0	0	0	0
All Days	Maximum %	9.96	7.78	8.11	9.96
	# Days > 5%	1	6	3	10
	# Days > 10%	0	0	0	0
Chassahowitzka NWA					
All Days except those with natural visibility impairment	Maximum	**3.11**	**5.35**	**3.77**	**5.35**
	# Days > 5%	0	1	0	1
	# Days > 10%	0	0	0	0
All Days	Maximum	3.11	8.14	6.73	8.14
	# Days > 5%	0	4	1	5
	# Days > 10%	0	0	0	0

[a] Light extinction based on the new IMPROVE equation developed by the IMPROVE Steering Committee was calculated in the CALPOST-IMPROVE Processor (Version 2, dated October 14, 2006) which uses the results from current IMPROVE equation.
Maximum relatively humidity cap is 95 percent.

TABLE 7-8
MAXIMUM VISIBILITY IMPAIRMENT PREDICTED FOR THE FPL GLADES POWER PARK AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA (METHOD 2 INITIAL IMPROVE EQUATION)

Meteorological Data	Parameter	Method 2 [a] (PSD) 2001	2002	2003	MAX/ TOTAL
Everglades NP					
All Days except those with natural visibility impairment	Maximum	**4.9**	**9.8**	**9.4**	**9.8**
	# Days > 5%	0	4	5	9
	# Days > 10%	0	0	0	0
All Days	Maximum %	12.0	9.8	9.4	12.0
	# Days > 5%	1	11	6	18
	# Days > 10%	1	0	0	1
Chassahowitzka NWA					
All Days except those with natural visibility impairment	Maximum	**3.6**	**6.1**	**4.4**	**6.1**
	# Days > 5%	0	2	0	2
	# Days > 10%	0	0	0	0
All Days	Maximum	3.6	9.2	7.3	9.2
	# Days > 5%	0	5	1	6
	# Days > 10%	0	0	0	0

[a] The initial IMPROVE equation has been superseded by the IMPROVE Steering Committee.
Light extinction calculated using Method 2, which is based on hourly relative humidity observations.
Maximum relative humidity cap used is 95%.

TABLE 7-9
MAXIMUM ANNUAL SULFUR AND NITROGEN DEPOSITION PREDICTED FOR FGPP AT THE PSD CLASS I AREAS OF THE EVERGLADES NP AND CHASSAHOWITZKA NWA

Species	Total Deposition (Wet & Dry)		Year	Deposition Analysis Threshold[b]
	($g/m^2/s$)	(kg/ha/yr)[a]		(kg/ha/yr)
Everglades NP				
Sulfur (S) Deposition	3.95E-11	0.012	2001	0.01
	6.33E-11	0.020	2002	
	4.53E-11	0.014	2003	
Nitrogen (N) Deposition	1.34E-11	0.004	2001	0.01
	2.91E-11	0.009	2002	
	1.98E-11	0.006	2003	
Chassahowitzka NWA				
Sulfur (S) Deposition	5.55E-11	0.018	2001	0.01
	5.27E-11	0.017	2002	
	4.77E-11	0.015	2003	
Nitrogen (N) Deposition	2.82E-11	0.0089	2001	0.01
	2.65E-11	0.0084	2002	
	2.55E-11	0.0080	2003	

[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

$g/m^2/s$	x	0.001 kg/g
	x	10,000 m^2/hectare
	x	3,600 sec/hr
	x	8,760 hr/yr = kg/ha/yr
	or	
$g/m^2/s$	x	3.154E+08 = kg/ha/yr

[b] Deposition analysis thresholds (DAT) for nitrogen and sulfur deposition provided by the U.S. Fish and Wildlife Service, January 2002. A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a proposed new or modified source are considered insignificant.

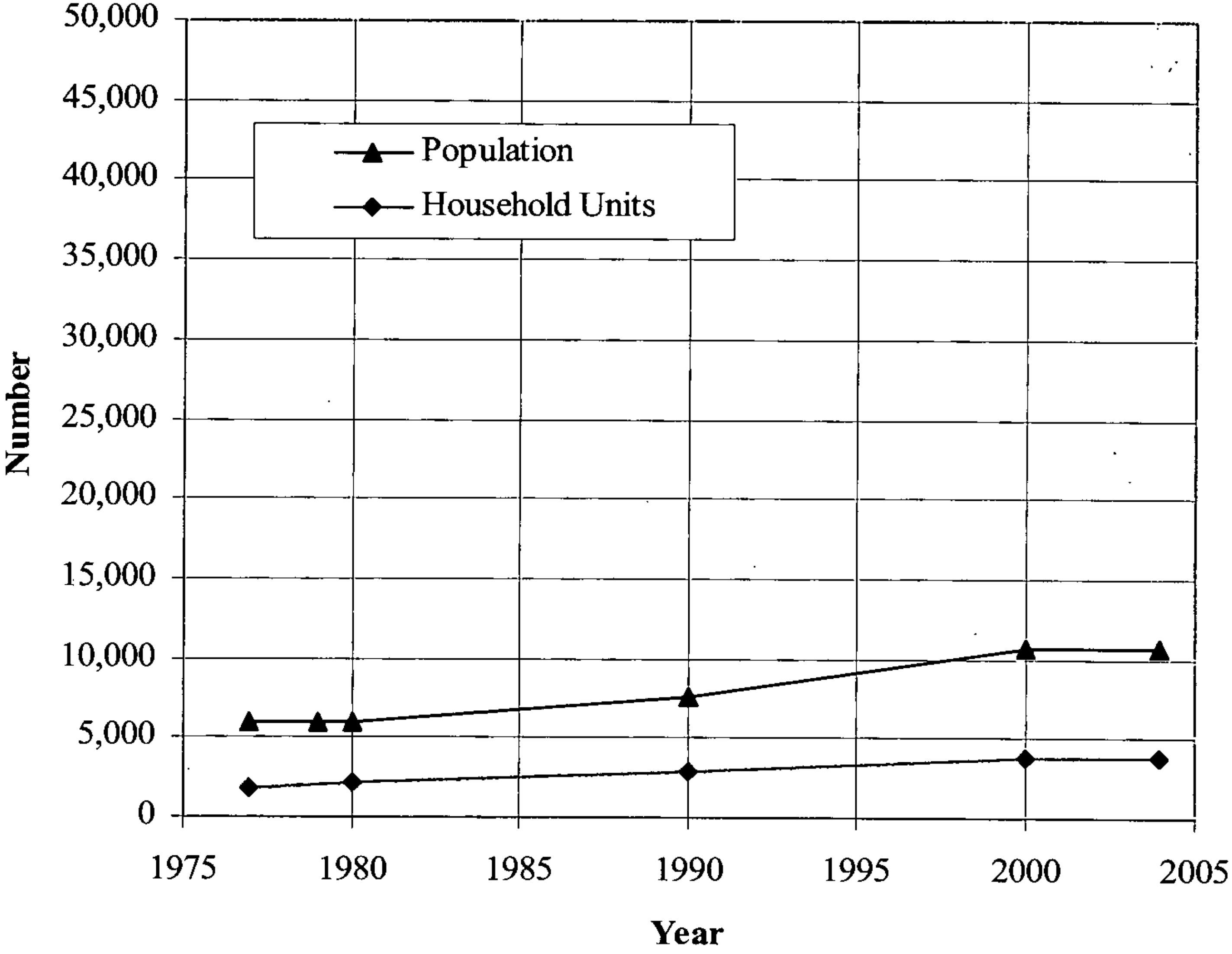

Figure 7-1
Population and Household Unit Trends in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

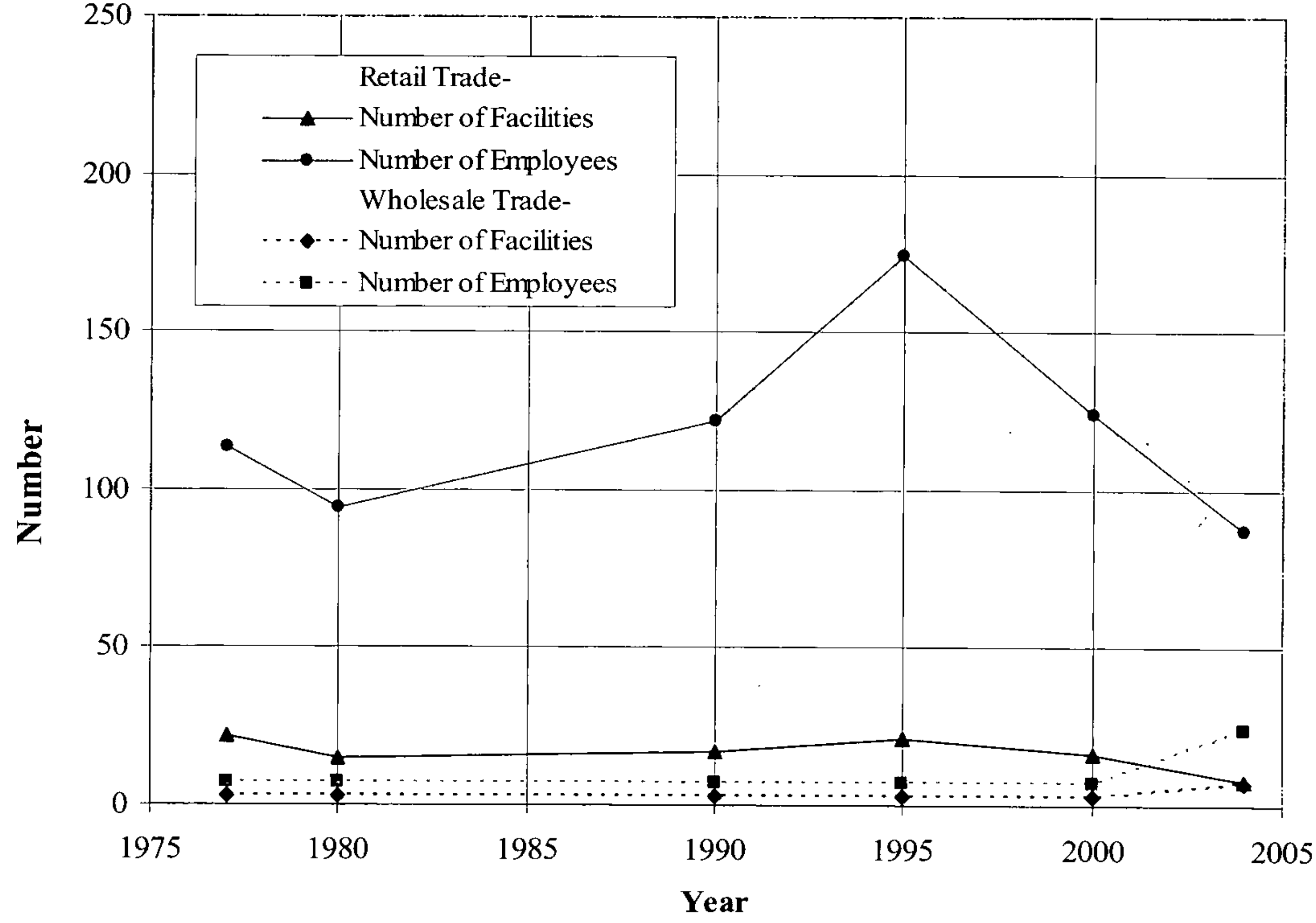

Figure 7-2
Retail and Wholesale Trade Trends in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

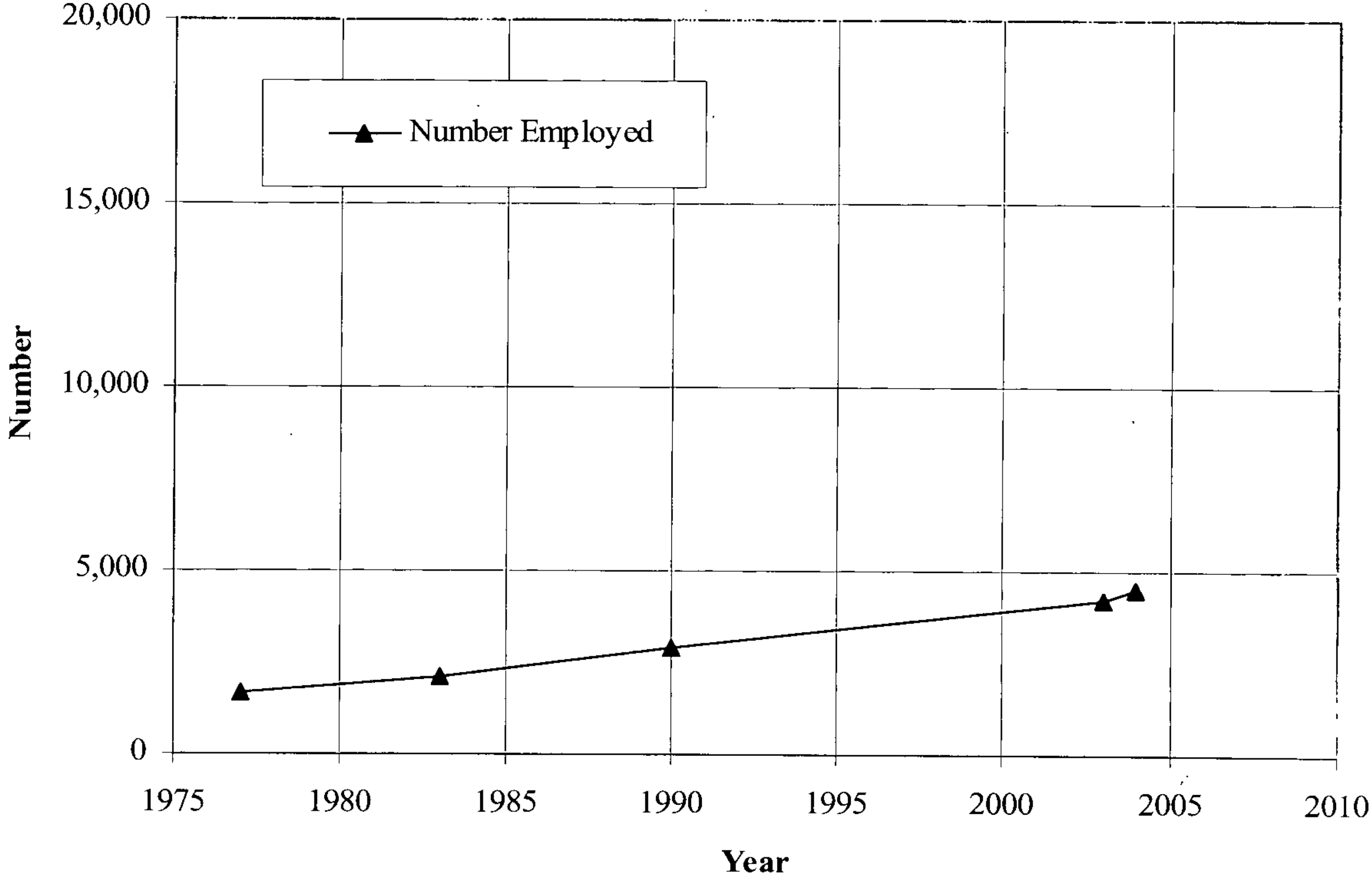

Figure 7-3
Labor Force Trends in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

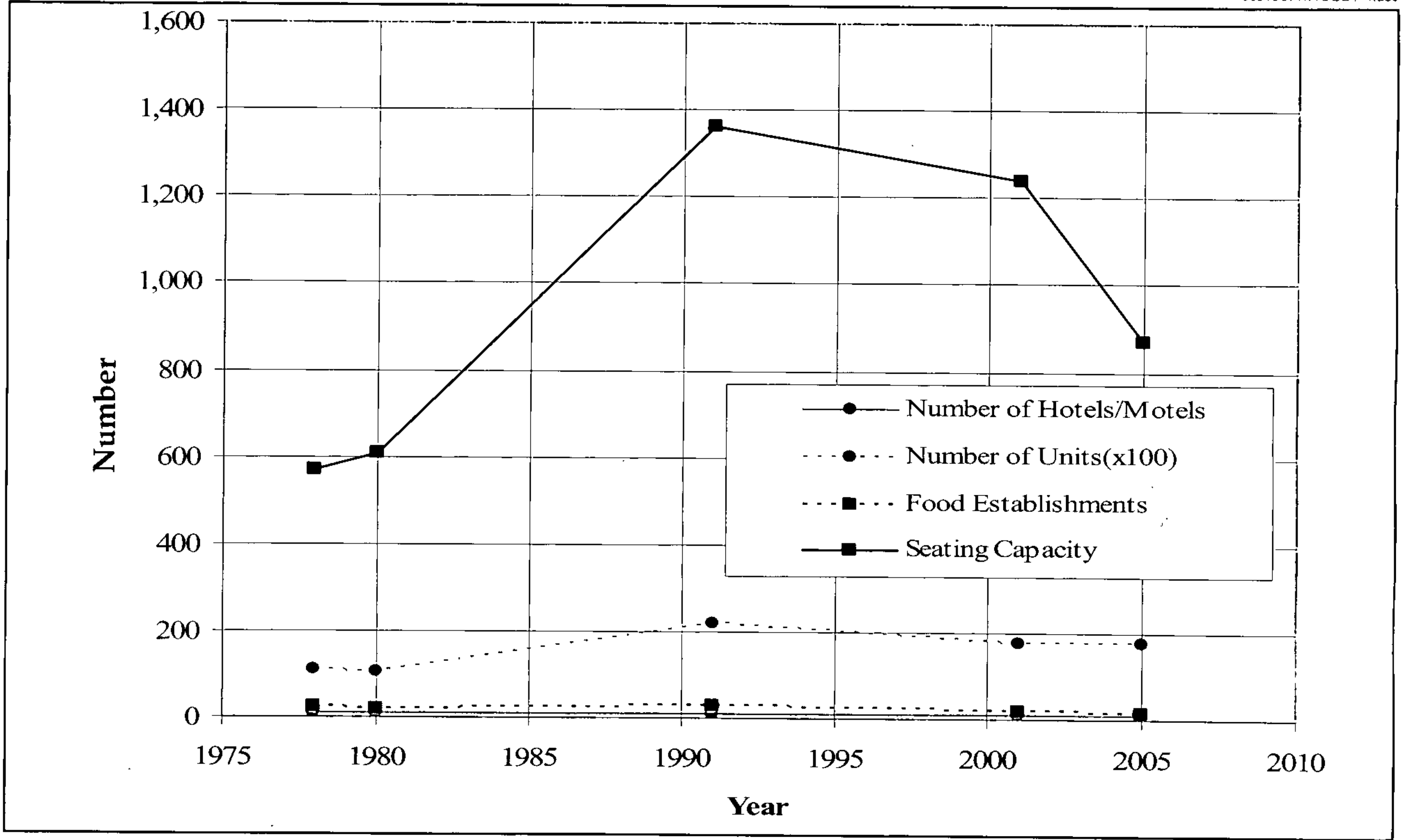

Figure 7-4
Hotel, Motel, and Food Establishment Trends in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

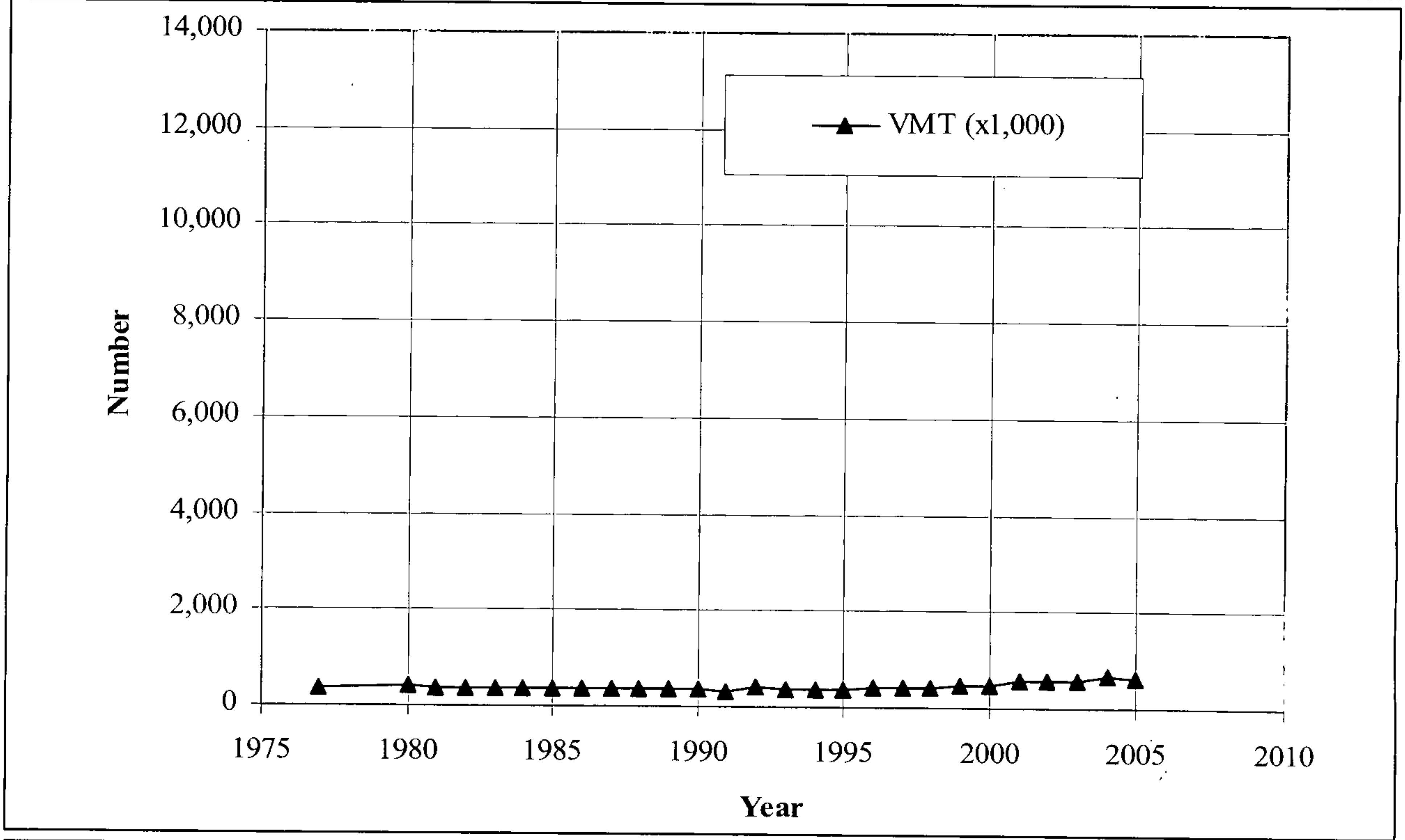

Figure 7-5
Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

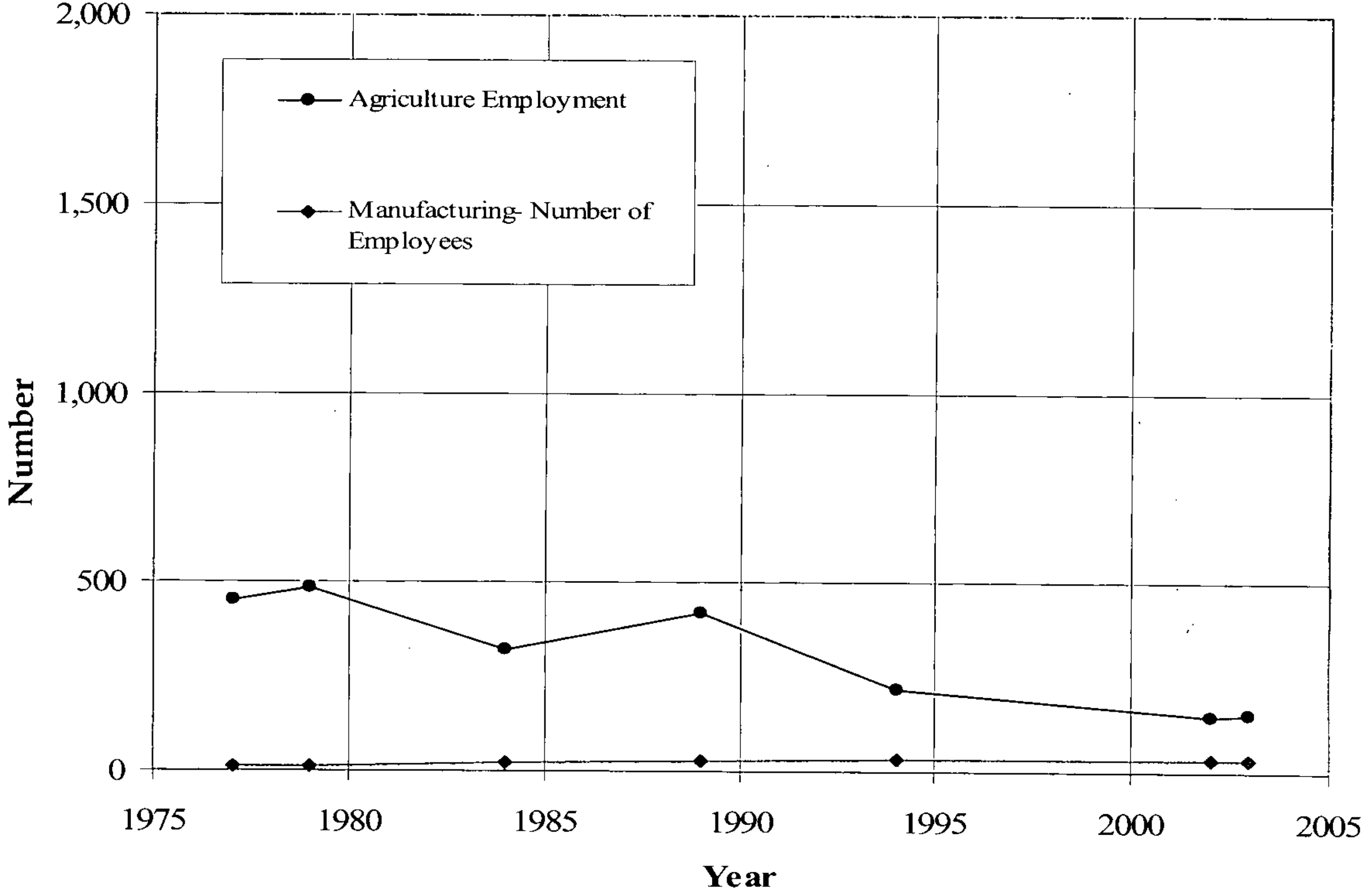

Figure 7-6
Manufacturing and Agriculture Trends in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

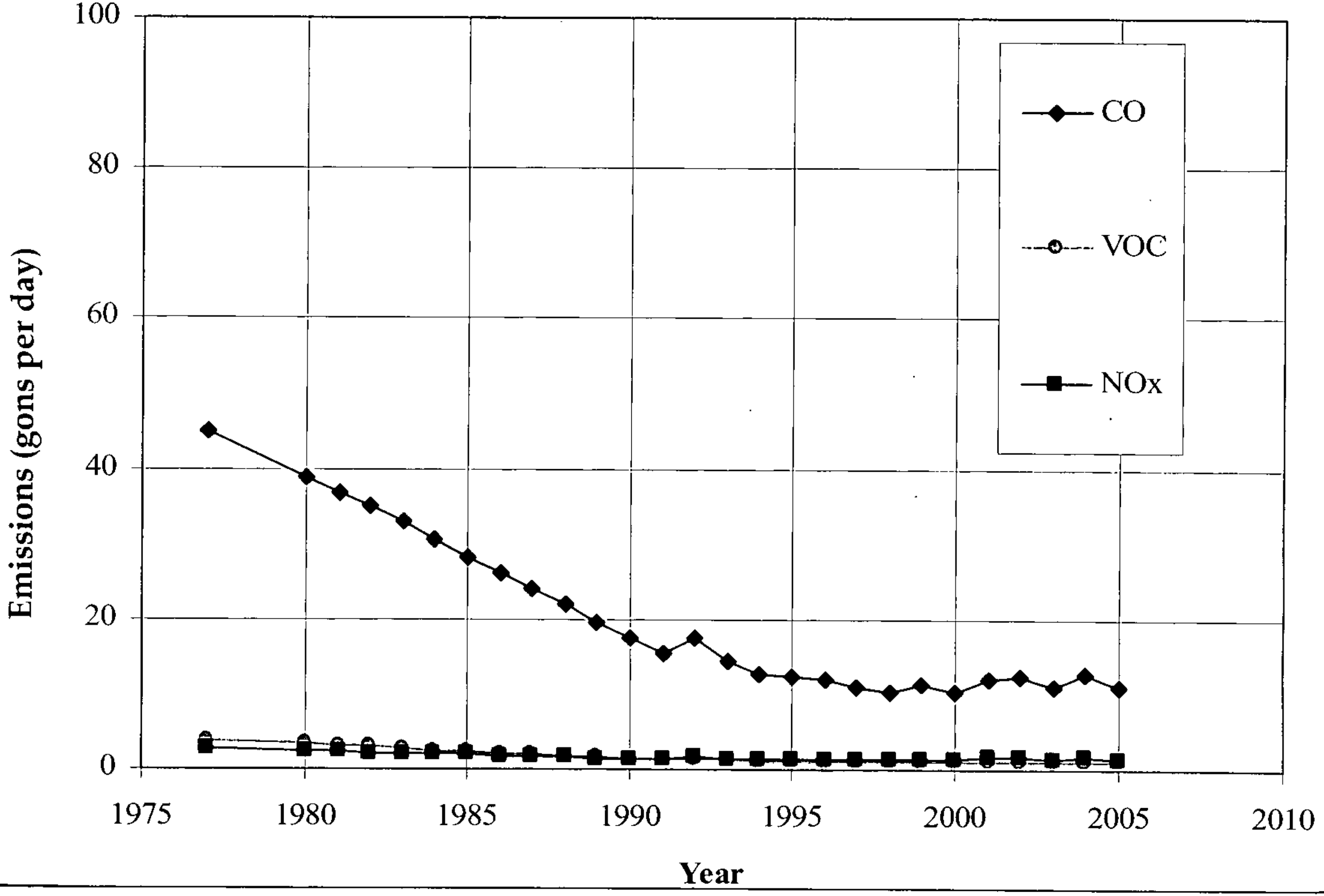

Figure 7-7
Mobile Source Emissions (Tons per Day) of CO, VOC, and NO_x in Glades County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

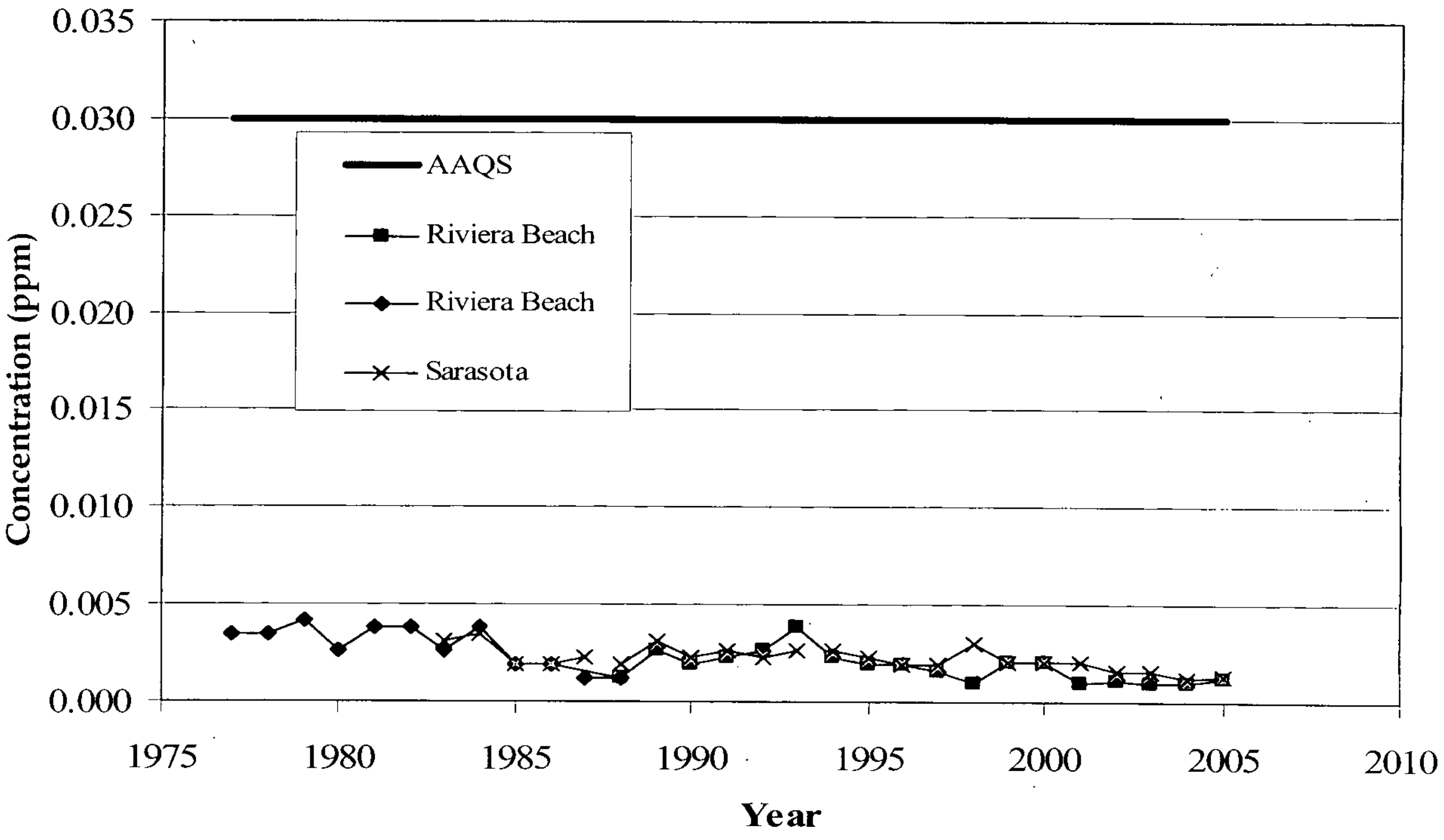

Figure 7-8
Annual Average Sulfur Dioxide Concentrations Measured from 1977 to 2005- Palm Beach and Sarasota Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

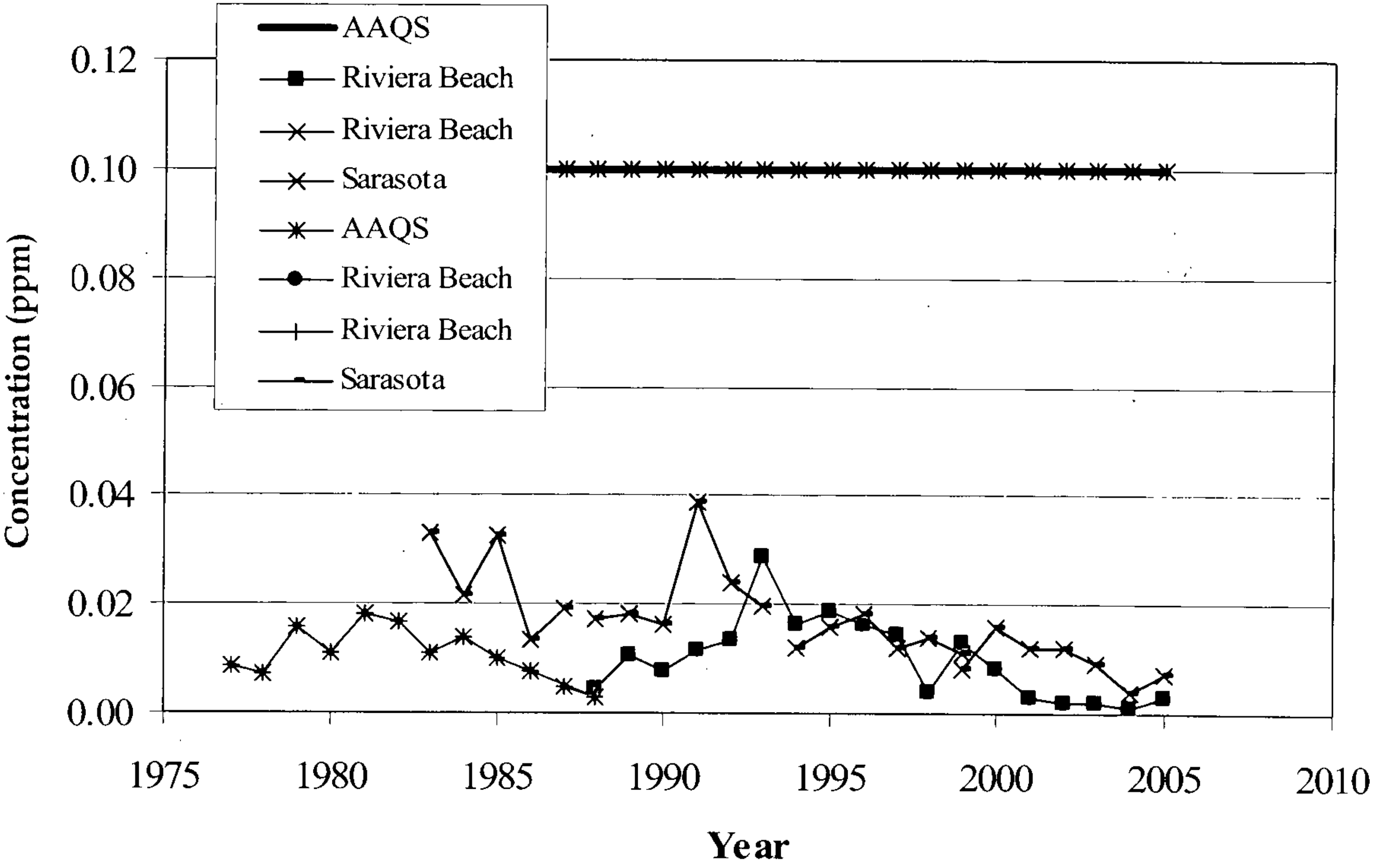

Figure 7-9
24-hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured
from 1977 to 2005- Palm Beach and Sarasota Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

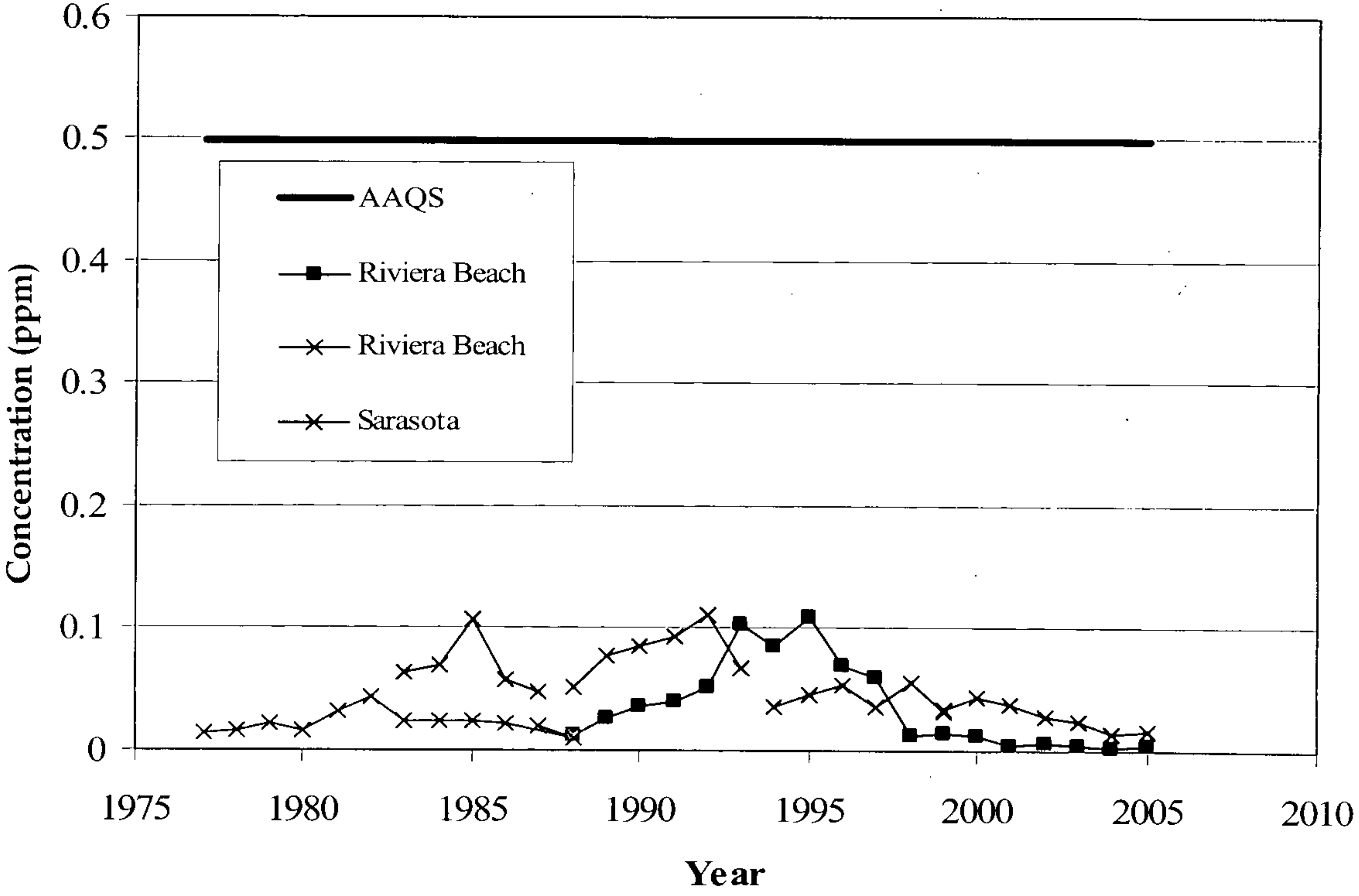

Figure 7-10
3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured
from 1977 to 2005- Palm Beach and Sarasota Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder. 2006.

Golder Associates

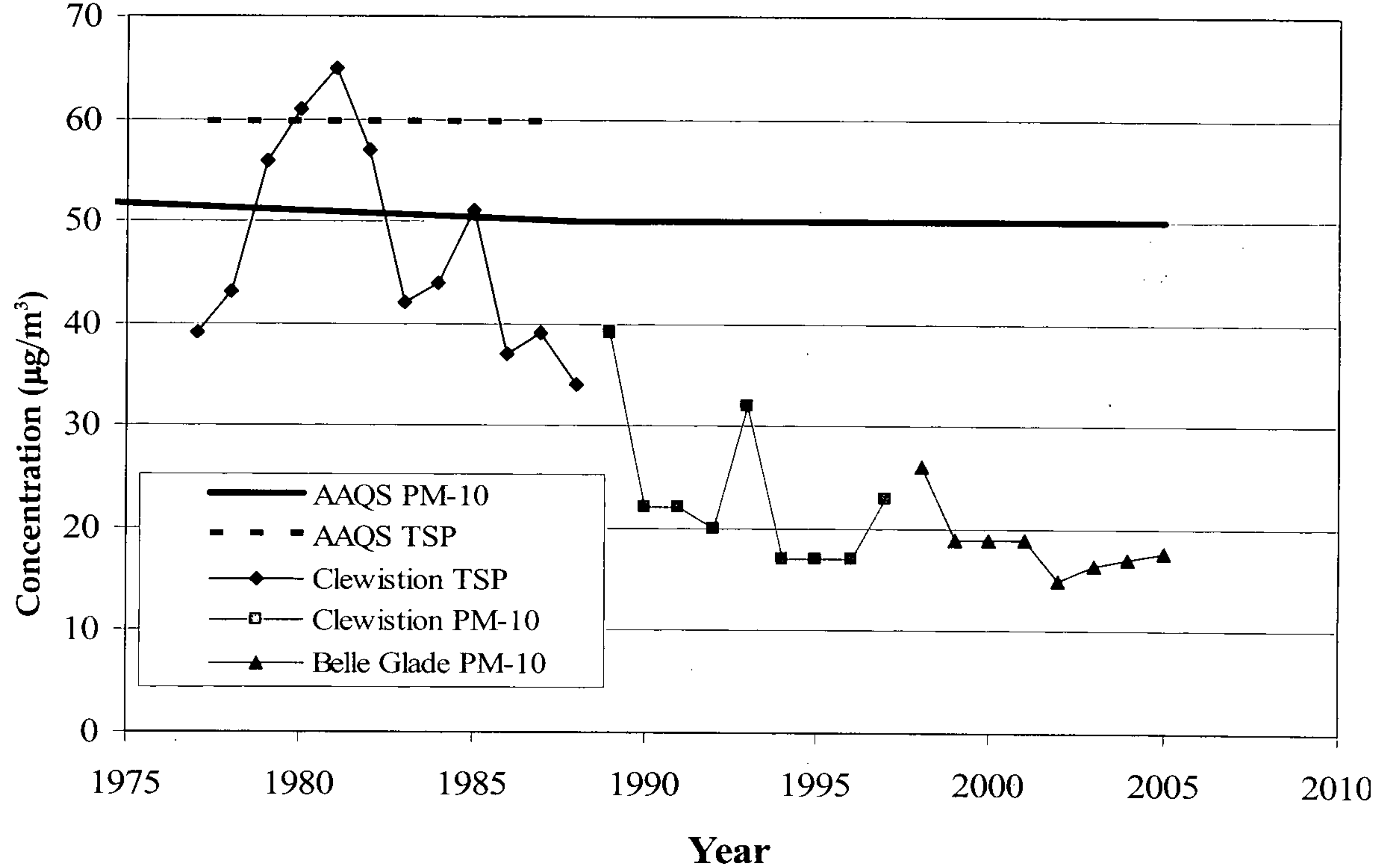

Figure 7-11
Measured Annual Average PM_{10} Concentrations and TSP Concentrations from 1977 to 2005 in Hendry and Palm Beach Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

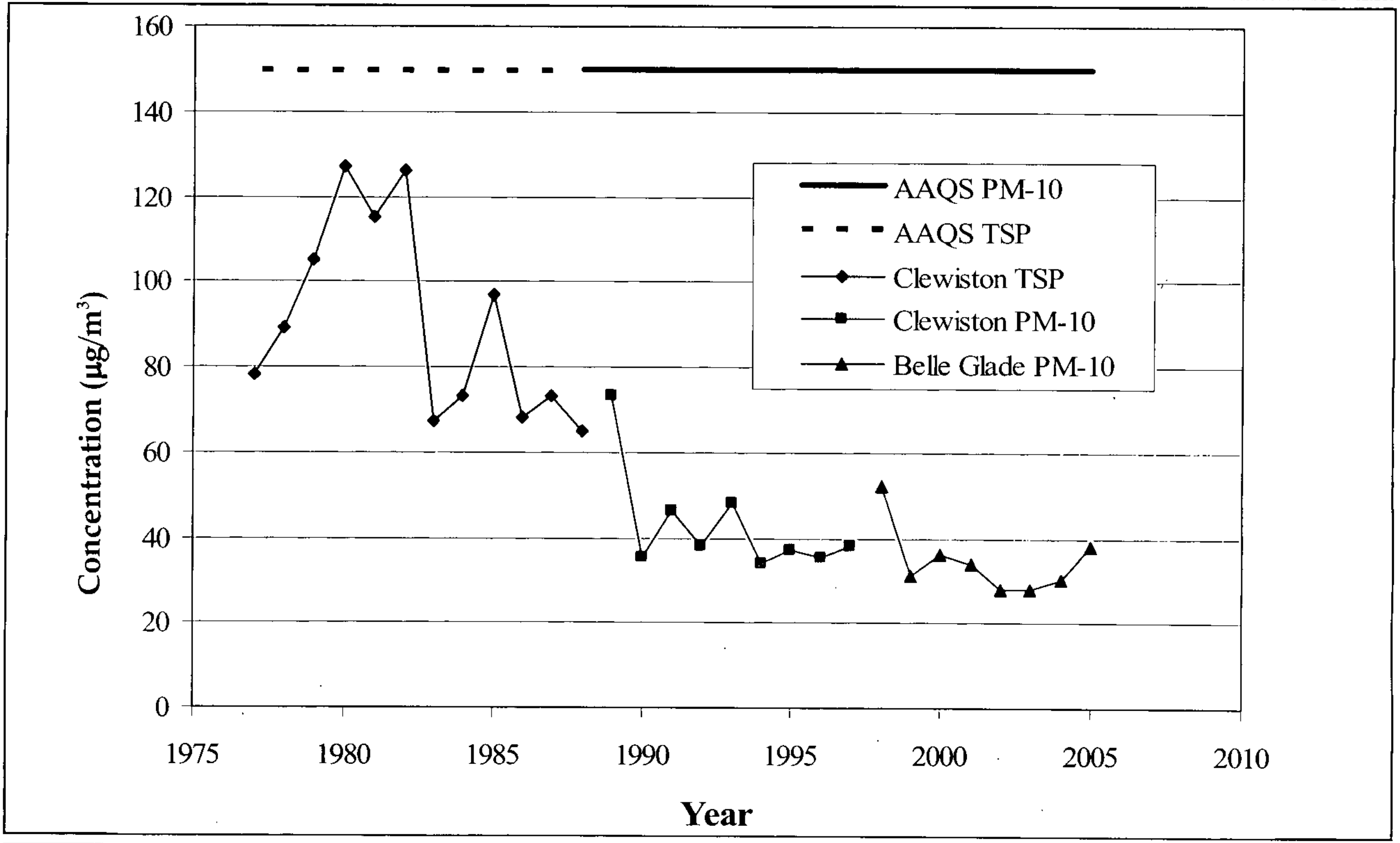

Figure 7-12
Measured 24-Hour Average PM_{10} Concentrations and TSP Concentrations (2nd Highest Values) from 1977 to 2005 in Hendry and Palm Beach Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

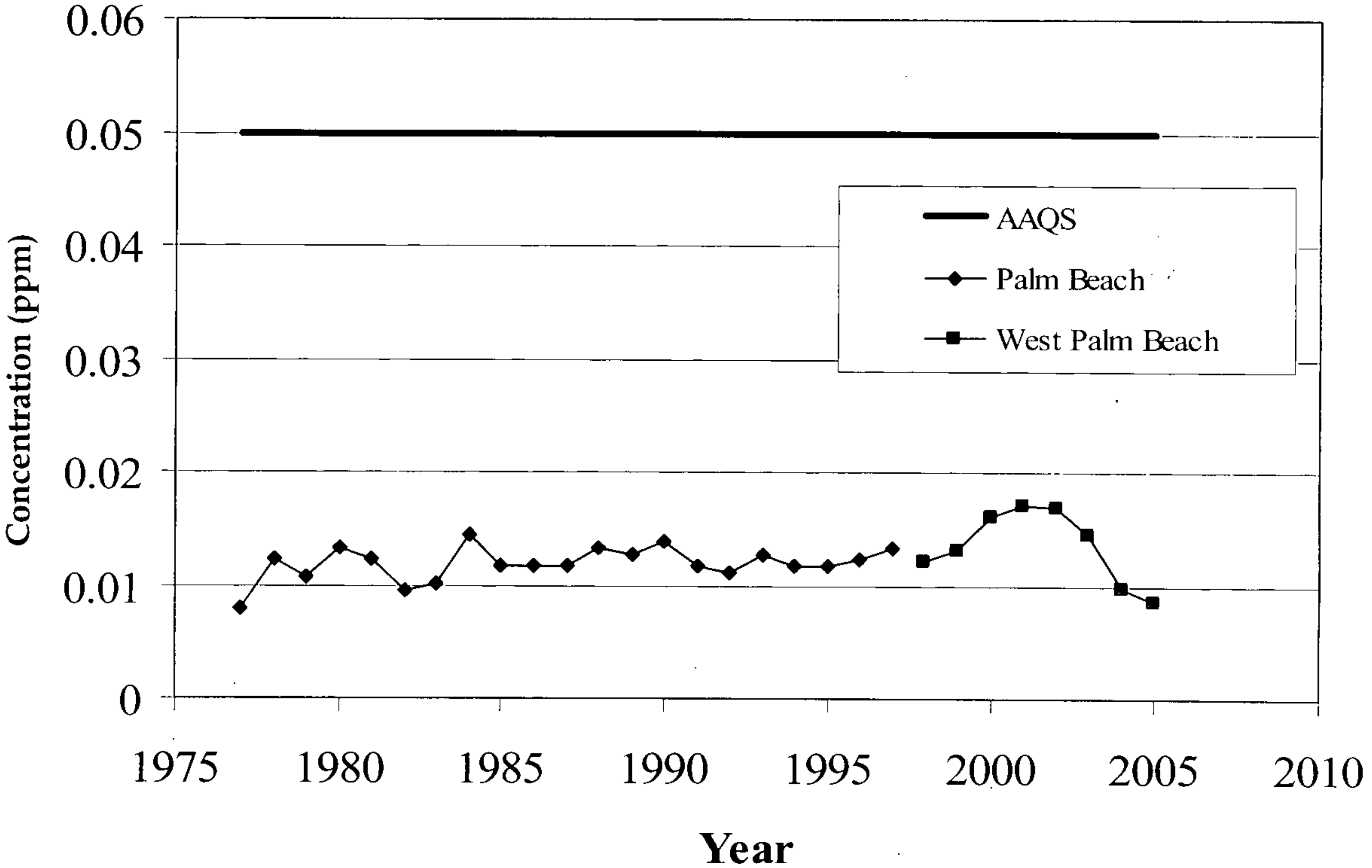

Figure 7-13
Measured Annual Average NO_2 Concentrations
from 1977 to 2005 in Palm Beach County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

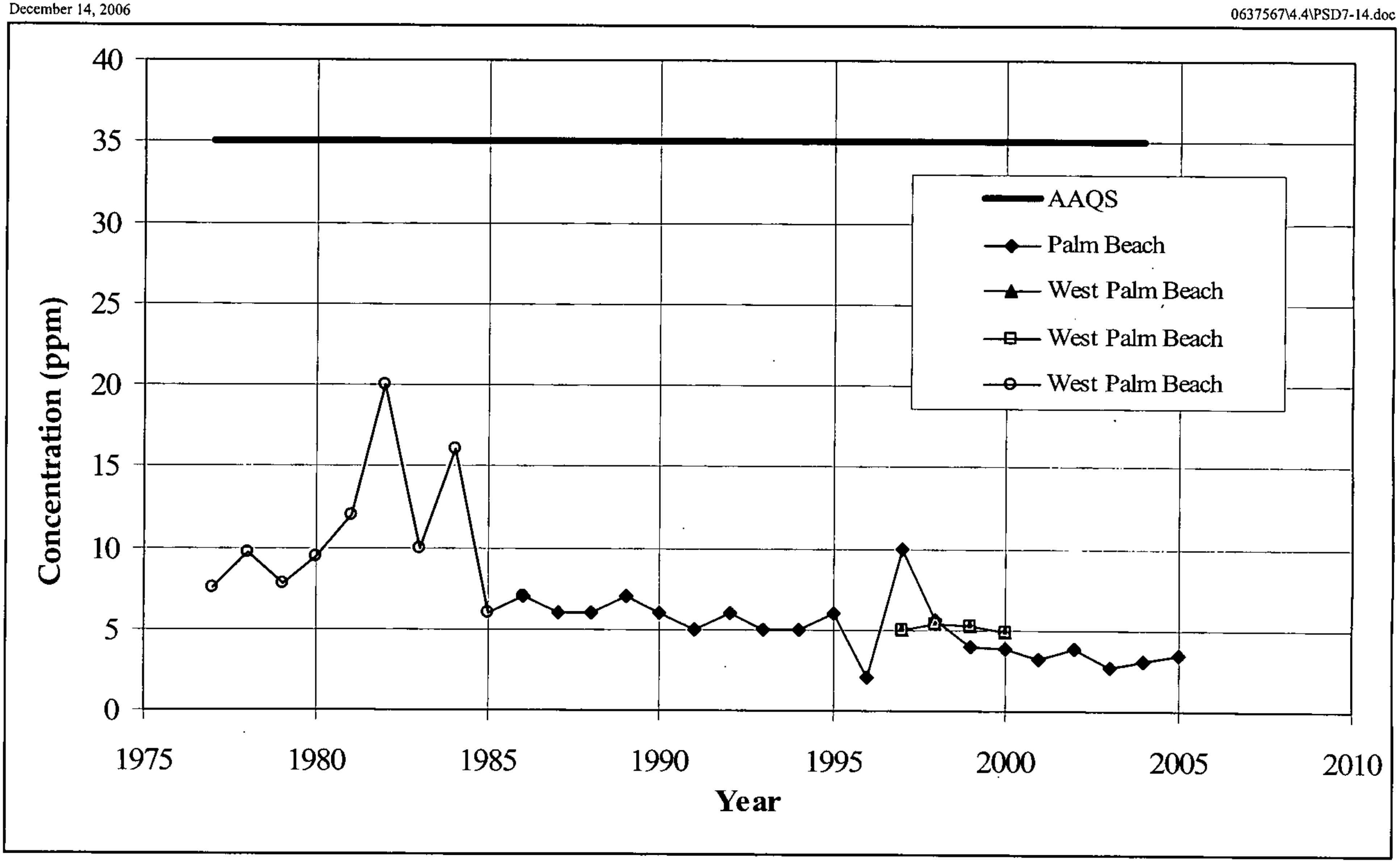

Figure 7-14
1-Hour Average Carbon Monoxide Concentrations (2nd Highest Values)
Measured from 1977 to 2005 in Palm Beach County
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

Golder Associates

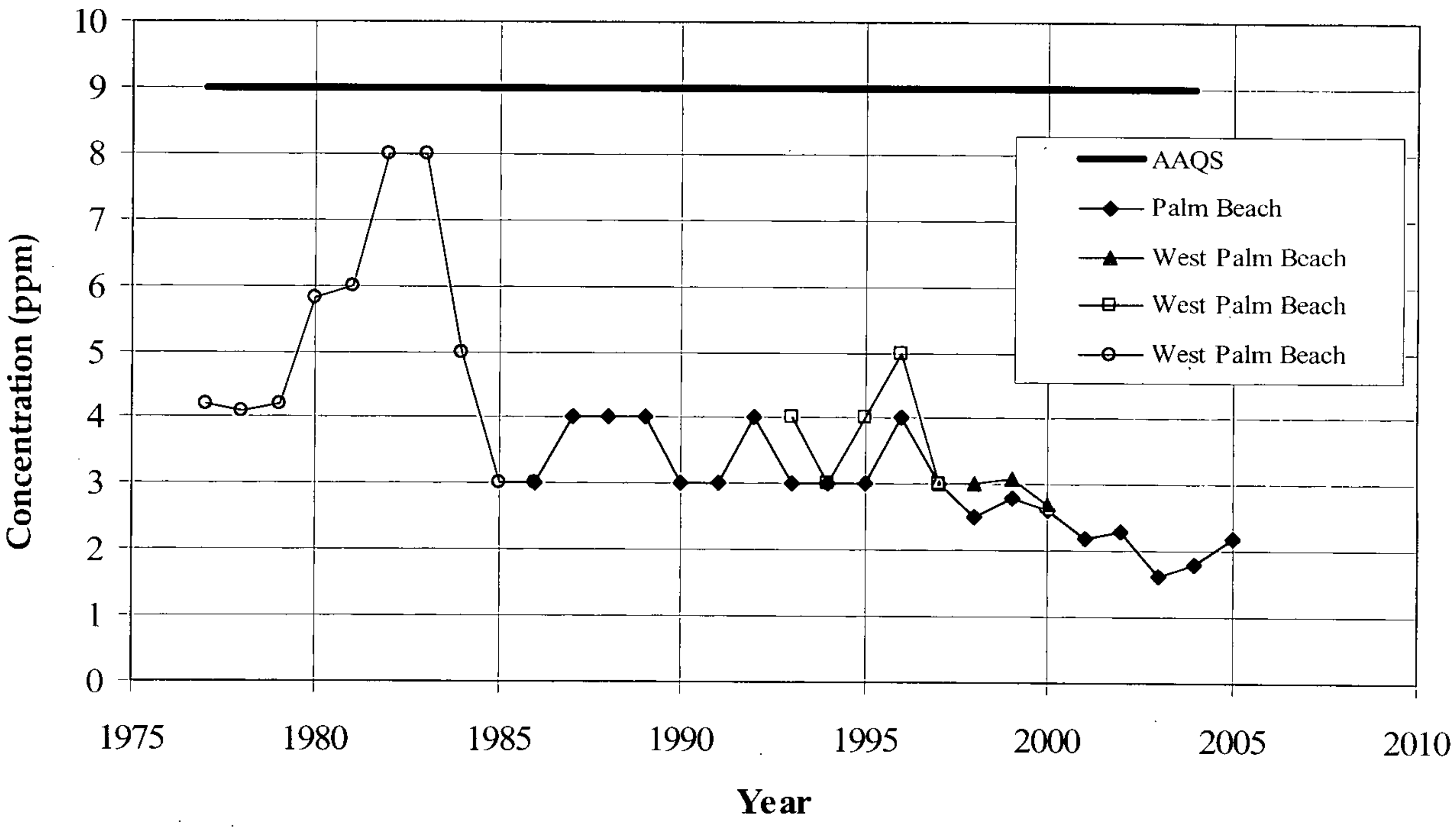

Figure 7-15
8-Hour Average Carbon Monoxide Concentrations (2nd Highest Values)
Measured from 1977 to 2005 in Palm Beach County
FPL Glades Power Park, Glades County, Florida

Source: Golder. 2006.

Golder Associates

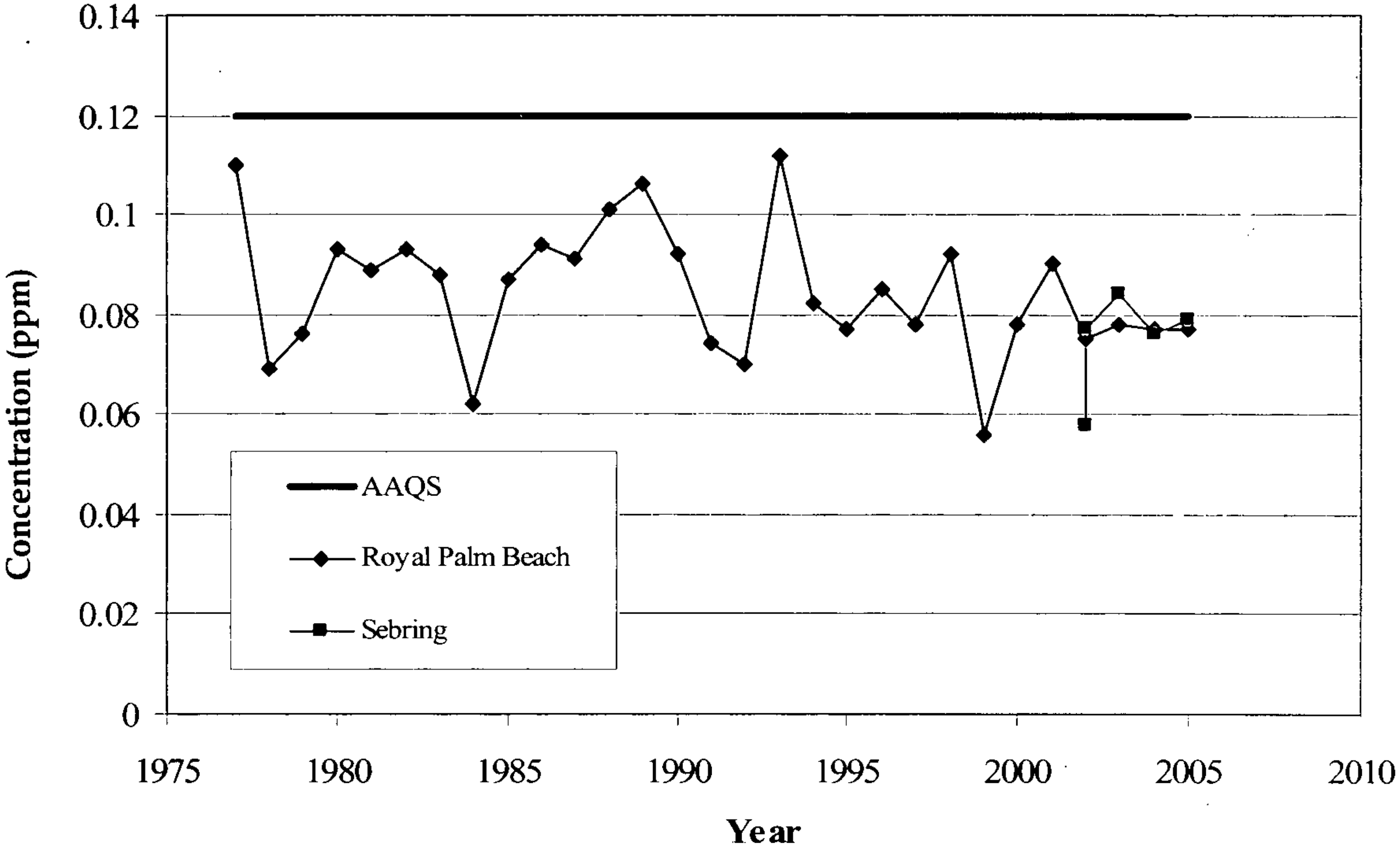

Figure 7-16
1-Hour Average Ozone Concentrations (2nd Highest Values)
Measured from 1977 to 2005 in Highland and Palm Beach Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

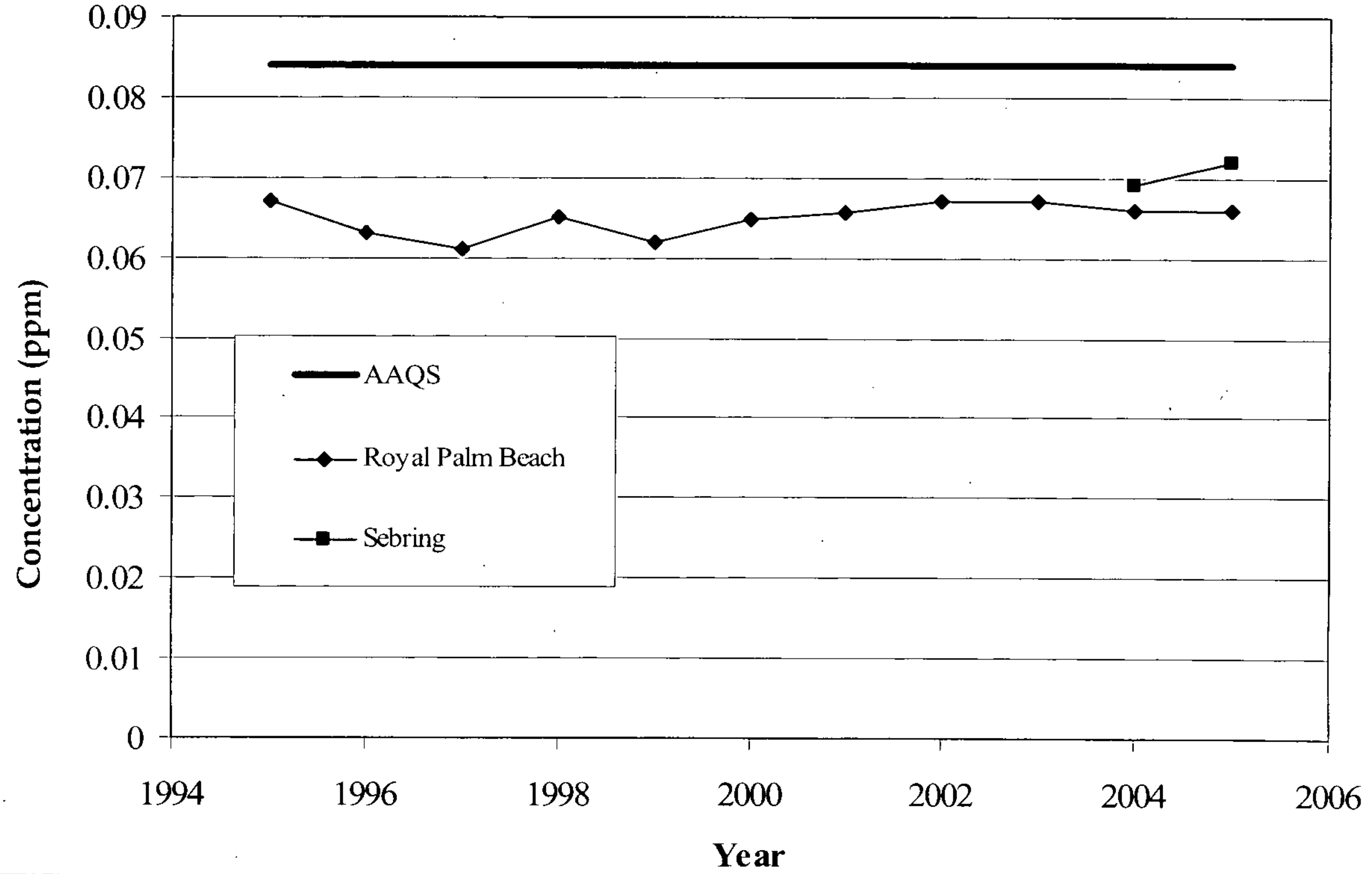

Figure 7-17
8-Hour Average Ozone Concentrations (3-year Average of the 4th Highest Values)
Measured from 1995 to 2005 in Highland and Palm Beach Counties
FPL Glades Power Park, Glades County, Florida

Source: Golder, 2006.

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APPENDIX A

EMISSION INFORMATION

EMISSIONS FROM
MATERIAL HANDLING

TABLE A-1
SUMMARY OF PM EMISSIONS FROM THE MATERIAL HANDLING OPERATIONS
PROJECT: FPL GLADES POWER PARK

	Emission Rate (lb/hr)		Emission Rate (TPY)	
Operation	**PM 24-hour Rate**	**PM10 24-hour Rate**	**PM Annual Rate**	**PM10 Annual Rate**
Coal Handling System				
Emission Points	0.98	0.98	4.30	3.82
Transfer Points (Fugitive)	0.44	0.21	1.30	0.61
Fugitive Emissions	1.78	0.54	3.06	0.88
Limestone Handling System- Dust Collection and Ventilation				
Emission Points	0.04	0.04	0.20	0.15
Transfer Points (Fugitive)	0.25	0.12	1.98	0.94
Fugitive Emissions	0.57	0.13	1.01	0.22
Fly Ash Handling System				
Emission Points	0.26	0.26	1.13	1.13
Transfer Points (Fugitive)	0.051	0.024	0.121	0.057
Bottom Ash Handling System				
Transfer Points (Fugitive)	0.0318	0.0150	0.0760	0.0359
Fugitive Emissions	0.14	0.03	0.42	0.09
Gypsum Handling System				
Transfer Points (Fugitive)	0.114	0.054	0.912	0.431
Fugitive Emissions	0.004	0.001	0.006	0.002
Byproduct Handling System				
Fugitive Emissions	5.64	1.21	20.18	4.10
Reagent Handling System				
Emission Points	0.03	0.03	0.13	0.13
TOTAL EMISSIONS	10.34	3.64	34.80	12.60
Number of Sources	53			

Emission Point	Flowrate Maximum Capacity (cfm)	Average Daily Operation (hours)		Factor and Rate Daily Hourly Rate (lb/hr)	(g/s)	Annual Rate (TPY)
<u>Coal Handling System- Ventilation and Dust Collection</u>						
EP-45	18,000	4.62	Railcar u	0.035	0.0044	0.15
EP-46	2,800	4.62	Transfer	0.017	0.0022	0.08
			Transfer	0.0000	0.0000	0.00
EP-47	3,750	0.00				
EP-61	1,000	4.62	Crusher	0.016	0.0021	0.072
EP-61A	15,000	4.62	Crusher	0.022	0.0028	0.098
EP-61B	15000	4.62	Crusher	0.022	0.0028	0.098
EP-52	23000	4.62	Tripper t	0.379	0.0478	1.66
EP-53	23000	4.62	Tripper t	0.379	0.0478	1.66
<u>Limestone Handling System- Dust Collection and Ventilation</u>						
EP-65	1,000	3.42	Day bins	0.0122	0.00154	0.054
EP-66	1,000	3.42	Day bins	0.0122	0.00154	0.054
EP-68	3,000	1.37	Rail bott hopper	0.010	0.0012	0.043
<u>Fly Ash Handling System</u>						
EP-70	3,000	12	Flyash sil	0.13	0.0162	0.56
EP-70A	3,000	0	Flyash sil	0.00	0.0000	0.00
EP-72	3,000	12	Flyash si	0.13	0.0162	0.56
EP-72A	3,000	0	Flyash sil	0.00	0.0000	0.00
<u>Reagent Silos</u>						
EP-REAG1	1,000	4	Reagent	0.0143	0.0018	0.06
EP-REAG2	1,000	4	Reagent	0.0143	0.0018	0.06
TOTAL EMISSIONS				1.19		5.22
Number of Emission Points	17					

a Emissions based on emission factors from AP-42. See Appen

b Based on hours from transfer point

c Grain loading provided

TABLE A-2A
SUMMARY OF STACK AND OPERATING PARAMETERS FOR THE PM EMISSION POINTS FOR THE MATERIAL HANDLING OPERATIONS
PROJECT: FPL GLADES POWER PARK

		Stack/Vent Data				Operating Data	
		Height		Diameter		Velocity	
Emission Point	Activity/Operation	(ft)	(m)	(ft)	(m)	(ft/s)	(m/s)
Coal Handling System- Ventilation and Dust Collection							
EP-45	Railcar unloading	10	3.05	4	1.22	24	7.28
EP-46	Transfer Tower No. 1	100	30.5	2	0.61	15	4.53
EP-47	Transfer Tower No. 2	70	21.3	2	0.61	20	6.07
EP-61	Crusher tower	130	39.6	1.5	0.46	9.4	2.88
EP-61A	Crusher tower	130	39.6	4	1.22	20	6.07
EP-61B	Crusher tower	130	39.6	4	1.22	20	6.07
EP-52	Tripper to silos	250	76.2	4	1.22	31	9.30
EP-53	Tripper to silos	250	76.2	4	1.22	31	9.30
Limestone Handling System- Dust Collection and Ventilation							
EP-65	Day bins	140	42.7	1.5	0.46	9.4	2.88
EP-66	Day bins	140	42.7	1.5	0.46	9.4	2.88
EP-68	Rail bottom dumper hopper	10	3.0	2	0.61	16	4.85
Fly Ash Handling System							
EP-70	Flyash silos	105	32.0	2	0.61	16	4.85
EP-70A	Flyash silos	105	32.0	2	0.61	16	4.85
EP-72	Flyash silos	105	32.0	2	0.61	16	4.85
EP-72A	Flyash silos	105	32.0	2	0.61	16	4.85
Reagent Silos							
EP-REAG1	Reagent Silo- Water Treatment	50	15.2	1.5	0.46	9.4	2.88
EP-REAG2	Reagent Silo- Boiler	50	15.2	1.5	0.46	9.4	2.88

TABLE A-3
SUMMARY OF PM EMISSIONS FOR TRANSFER POINTS (FUGITIVE EMISSIONS) FROM THE MATERIAL HANDLING OPERATIONS
PROJECT: FPL GLADES POWER PARK

			Emission Rate (lb/hr)		**Emission Rate (TPY)**	
Emission Point		**Activity/Operation**	**PM 24-hour Rate**	**PM10 24-hour Rate**	**PM Annual Rate**	**PM10 Annual Rate**
Coal Handling System- Dust Collection and Ventilation						
TP-1		Railcar unloading	0.099	0.047	0.236	0.111
TP-5		Active coal stockout pile	0.296	0.140	0.942	0.446
TP-11	a	Inactive coal stockout pile	0.000	0.000	0.000	0.000
TP-26		Active coal stockout pile	0.025	0.012	0.059	0.028
TP-27		Active coal stockout pile	0.025	0.012	0.059	0.028
Limestone Handling System- Dust Collection and Ventilation						
TP-54		Bottom dumper unloading hopper	0.021	0.010	0.165	0.078
TP-56		Active limestone stockout pile	0.021	0.010	0.165	0.078
TP-61		Active limestone stockout pile	0.103	0.049	0.824	0.390
TP-62		Active limestone stockout pile	0.103	0.049	0.824	0.390
Fly Ash Handling System						
TP-71/TP-71A	b	Loadout to truck, silo area- Unit 1	0.0254	0.0120	0.0607	0.0287
TP-69/TP-69A	b	Loadout to truck, silo area- Unit 2	0.0254	0.0120	0.0607	0.0287
Bottom Ash Handling System						
TP-73		Storage bunker, near boiler- Unit 1	0.0159	0.00752	0.0380	0.01797
TP-76		Storage bunker, near boiler- Unit 2	0.0159	0.00752	0.0380	0.01797
Gypsum Handling System						
TP-79		Transfer from dewatering bldg to conveyor- Unit 1	0.019	0.0090	0.152	0.072
TP-81		Transfer from dewatering bldg to conveyor- Unit 2	0.019	0.0090	0.152	0.0719
TP-82		Transfer from pile to truck- Unit 1	0.019	0.0090	0.152	0.0719
TP-83		Transfer from pile to truck- Unit 2	0.019	0.0090	0.152	0.0719
TP-87		Transfer from pile to rail	0.038	0.018	0.304	0.144
TOTAL EMISSIONS			0.89	0.42	4.38	2.07
Number of Transfer Points			17			

a TP-11 emissions are accounted for in TP-5.

b TP-71 and 69 accounts for emissions from TP-69A and TP-71A

TABLE A-4
IMARY OF PM EMISSIONS FOR FUGITIVE EMISSIONS SOURCES FROM THE MATERIAL HANDLING OPERATI
PROJECT: FPL GLADES POWER PARK

		Emission Rate (lb/hr)		Emission Rate (TPY)	
Emission Point		**PM 24-hour Rate**	**PM10 24-hour Rate**	**PM Annual Rate**	**PM10 Annual Rate**
Coal Handling System- Dust Collection and Ventilation					
Wind erosion					
F-6 Fuel A	Active pile	0.38	0.12	0.54	0.17
F-6 Pet Coke	Active pile	0.38	0.12	0.54	0.17
F-6 Fuel B	Active pile	0.38	0.12	0.54	0.17
F-14	Inactive pile	0.09	0.03	0.13	0.04
F-13	Inactive pile	0.21	0.07	0.30	0.10
Bulldozers					
F-12	Inactive pile	0.34	0.07	1.01	0.22
F-28 [a]	Inactive pile	0.00	0.00	0.00	0.00
Limestone Handling System- Dust Collection and Ventilation					
Wind erosion					
F-58	Active pile	0.02	0.01	0.03	0.01
Bulldozers					
F-57	Active pile	0.24	0.05	0.05	0.010
F-60	Active pile/ inactive pile	0.31	0.07	0.94	0.20
Bottom Ash Handling System					
Wind erosion					
F-74	Storage bunker, near Unit 1	0.0007	0.0002	0.0010	0.0003
F-77	Storage bunker, near Unit 2	0.0007	0.0002	0.0010	0.0003
F-83	Storage pile	0.0111	0.0036	0.0157	0.0051
Front end Loaders					
F-75	Storage pile	0.13	0.03	0.40	0.09
Gypsum Handling System					
Wind erosion					
F-84	Storage pile	0.002	0.001	0.003	0.001
F-85	Storage pile	0.002	0.001	0.003	0.001
Byproduct Handling System					
Wind erosion					
F-91	Byproduct storage area	0.81	0.26	1.14	0.37
Bulldozers and Truck, and Misc. Vehicles					
F-90	Byproduct storage area	0.47	0.10	1.43	0.31
F-95	Byproducts and Vehicles	4.36	0.85	17.61	3.42
TOTAL EMISSIONS		8.14	1.91	24.67	5.30
Number of Sources		19			

[a] Emissions accounted for in active storage since not normally used for operation.

TABLE A-5

ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE COAL-HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)

PROJECT: FPL GLADES POWER PARK

		Operations			
		Coal Handling TP-1	**Coal Handling TP-3**	**Coal Handling TP-4**	**Coal Handling TP-5**
Parameters		**Transfer Coal from Rotary Car to Hoppers**	**Transfer Coal from Hoppers to belt to Conveyor C-1**	**Transfer Coal from Conv. C-1 to Conv. C-2 in Transfer House#1**	**Transfer Coal from Tripper Conv. C-2 to Active Stockout Pile**
Emission Point/Area		TP-1	EP-45	EP-46	Active Coal Stackout Pile F-6
Operational Data					
Activity, hours	Daily	4.6	4.6	4.6	4.6
days	Annual	365	365	365	365
Material Handling Data					
Material type		Coal	Coal	Coal	Coal
Material throughput, ton/hr (design)	Hourly	4,000	3,000	3,000	3,000
ton/day	Daily	18,478 a	13,858 a	13,858 a	13,858
ton/yr	Annual	6,744,425	6,744,425	6,744,425	6,744,425
Moisture content (M), % (nominal)		6.5	6.5	6.5	6.5
Number of transfers		1	1	1	4
General/ Site Characteristics					
Mean wind speed, mph	Daily	11.0	11.0	11.0	11.0
	Annual	6.9	6.9	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35	0.35
Emission Control Data					
Emission control method		Watering and underground drop	Watering, below grade	Watering, enclosed building	Watering and low drops
Emission control removal efficiency, %		90	90	95	90
Emission Factor (EF) Equations					
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U/5)^{1.3}$/[$(M/2)^{1.4}$]				
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.001281	0.001281	0.001281	0.001281
	Annual	0.000699	0.000699	0.000699	0.000699
Controlled EF, lb/ton	Short term	0.000128	0.000128	0.000064	0.000128
	Annual	0.000070	0.000070	0.000035	0.000070
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.000606	0.000606	0.000606	0.000606
	Annual	0.000330	0.000330	0.000330	0.000330
Controlled EF, lb/ton	Short term	0.000061	0.000061	0.000030	0.000061
	Annual	0.000033	0.000033	0.000017	0.000033
Estimated Emission Rate (ER)					
PM ER lb/hr (daily basis)		0.099	0.074	0.037	0.296
TPY		0.236	0.236	0.118	0.942
PM10 ER lb/hr (daily basis)		0.047	0.035	0.017	0.140
TPY		0.111	0.111	0.056	0.446

Source: USEPA, 1995; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

a Value shown is based on maximum hourly throughput rate and average daily hours of operation

TABLE A-5

ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE COAL-HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

		Operations			
Parameters		**Coal Handling TP-9 Transfer Coal from Conv. C-1 to Conv. C-3 in Transfer House#1**	**Coal Handling TP-10 Transfer Coal from Conv. C-3 to Conv. C-4 in Transfer House#2**	**Coal Handling TP-11 Transfer coal from Conv. C-4 Telescopic Chute to Fuel A Stockout Pile**	**Coal Handling TP-15 Transfer Coal from Conv. C-3 to C-5 in Transfer House#2**
Emission Point/Area		EP-46	EP-47 Emergency Stock Not Normally Used: Same Emissions as active storage.		EP-47
Operational Data					
Activity, hours	Daily	0.0	0.00	0.00	0.00
days	Annual	365	365	365	365
Material Handling Data					
Material type		Coal	Coal	Coal	Coal
Material throughput, ton/hr (design)	Hourly	0	0	0	0
ton/day	Daily	0	0	0	0
ton/yr	Annual	0	0	0	0
Moisture content (M), % (nominal)		6.5	6.5	6.5	6.5
Number of transfers		1	1	1	1
General/ Site Characteristics					
Mean wind speed, mph	Daily	11.0	11.0	11.0	11.0
	Annual	6.9	6.9	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35	0.35
Emission Control Data					
Emission control method		Surfactant, enclosed building	Surfactant, enclosed building	Telescopic chute	Surfactant, enclosed building
Emission control removal efficiency, %		95	90	90	90
Emission Factor (EF) Equations					
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U / 5)^{1.3}$/[$(M / 2)^{1.4}$]				
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.001281	0.001281	0.001281	0.001281
	Annual	0.000699	0.000699	0.000699	0.000699
Controlled EF, lb/ton	Short term	0.000064	0.000128	0.000128	0.000128
	Annual	0.000035	0.000070	0.000070	0.000070
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.000606	0.000606	0.000606	0.000606
	Annual	0.000330	0.000330	0.000330	0.000330
Controlled EF, lb/ton	Short term	0.000030	0.000061	0.000061	0.000061
	Annual	0.000017	0.000033	0.000033	0.000033
Estimated Emission Rate (ER)					
PM ER	lb/hr (daily basis)	0.000	0.000	0.000	0.000
	TPY	0.000	0.000	0.000	0.000
PM10 ER	lb/hr (daily basis)	0.000	0.000	0.000	0.000
	TPY	0.000	0.000	0.000	0.000

Source: USEPA, 2006; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

TABLE A-5

ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE COAL-HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

		Operations		
Parameters		**Coal Handling TP-26 Transfer coal from Portal Reclaimer A to Conv. C-8**	**Coal Handling TP-27 Transfer coal from Portal Reclaimer B to Conv. C-8**	**Coal Handling TP-29 Transfer Coal from Fuels A&B Reclaim Hopper to Belt Feeder to Conv. C-9**
Emission Point		Active Coal Stackout Pile (No 02)	Active Coal Stackout Pile (No 02)	EP-49
Operational Data				Reclaim from Inactive Not Used
Activity, hours	Daily	4.62	4.62	0.00
days	Annual	365	365	365
Material Handling Data				
Material type		Coal	Coal	Coal
Material throughput, ton/hr (design)	Hourly	2,000	2,000	0
ton/day	Daily	9,239	9,239	0
ton/yr	Annual	3,372,212	3,372,212	0
Moisture content (M), % (nominal)		6.5	6.5	6.5
Number of transfers		1	1	1
General/ Site Characteristics				
Mean wind speed, mph	Daily	11.0	11.0	11.0
	Annual	6.9	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35
Emission Control Data				
Emission control method		Watering and underground	Watering and underground	Surfactant, enclosed- below grade
Emission control removal efficiency, %		95	95	90
Emission Factor (EF) Equations				
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U/5)^{1.3}$/$[(M/2)^{1.4}]$			
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]			
Calculated PM Emission Factor (EF)				
Uncontrolled EF, lb/ton	Short term	0.001281	0.001281	0.001281
	Annual	0.000699	0.000699	0.000699
Controlled EF, lb/ton	Short term	0.000064	0.000064	0.000128
	Annual	0.000035	0.000035	0.000070
Calculated PM10 Emission Factor (EF)				
Uncontrolled EF, lb/ton	Short term	0.000606	0.000606	0.000606
	Annual	0.000330	0.000330	0.000330
Controlled EF, lb/ton	Short term	0.000030	0.000030	0.000061
	Annual	0.000017	0.000017	0.000033
Estimated Emission Rate (ER)				
PM ER	lb/hr (daily basis)	0.025	0.025	0.000
	TPY	0.059	0.059	0.000
PM10 ER	lb/hr (daily basis)	0.012	0.012	0.000
	TPY	0.028	0.028	0.000

Source: USEPA, 2006; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles

TABLE A-5

ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE COAL-HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

Parameters		Operations: Coal Handling TP-32 Transfer coal from Active Stackout Reclaim Conv. C-8 to Surge Bin-Crusher House	Operations: Coal Handling TP-35 Transfer coal from Crusher House Surge Bin to Belt Feeder BF-4A
Emission Point		EP-61, EP-61A&B	EP-61, EP-61A&B
Operational Data			
Activity, hours	Daily	4.62	4.62
days	Annual	365	365
Material Handling Data			
Material type		Coal	Coal
Material throughput, ton/hr (design)	Hourly	4,000	1,000
ton/day	Daily	18,478	4,619
ton/yr	Annual	6,744,425	1,686,106
Moisture content (M), % (nominal)		6.5	6.5
Number of transfers		1	1
General/ Site Characteristics			
Mean wind speed, mph	Daily	11.0	11.0
	Annual	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35
Emission Control Data			
Emission control method		Fog type dust suppressant, enclosed building	Fog type dust suppressant, enclosed building
Emission control removal efficiency, %		95	90
Emission Factor (EF) Equations			
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U / 5)^{1.3}$/$[(M / 2)^{1.4}]$		
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]		
Calculated PM Emission Factor (EF)			
Uncontrolled EF, lb/ton	Short term	0.001281	0.001281
	Annual	0.000699	0.000699
Controlled EF, lb/ton	Short term	0.000064	0.000128
	Annual	0.000035	0.000070
Calculated PM10 Emission Factor (EF)			
Uncontrolled EF, lb/ton	Short term	0.000606	0.000606
	Annual	0.000330	0.000330
Controlled EF, lb/ton	Short term	0.000030	0.000061
	Annual	0.000017	0.000033
Estimated Emission Rate (ER)			
PM ER lb/hr (daily basis)		0.049	0.025
TPY		0.118	0.059
PM10 ER lb/hr (daily basis)		0.023	0.012
TPY		0.056	0.028

Source: USEPA, 2006, AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

TABLE A-5

ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE COAL-HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

Parameters		Operations Coal Handling TP-35A Transfer coal from Crusher House Surge Bin to Belt Feeder BF-4B	Operations Coal Handling TP-37 Transfer coal from Belt Feeder BF-4A to Conv. C-11A Crusher House	Operations Coal Handling TP-37A Transfer coal from Belt Feeder BF-4A to Conv. C-11A- Crusher House
Emission Point		EP-61, EP-61A&B	EP-61, EP-61A&B	EP-61, EP-61A&B
Operational Data				
Activity, hours	Daily	4.62	4.62	4.62
days	Annual	365	365	365
Material Handling Data				
Material type		Coal	Coal	Coal
Material throughput, ton/hr (design)	Hourly	1,000	1,000	1,000
ton/day	Daily	4,619	4,619	4,619
ton/yr	Annual	1,686,106	1,686,106	1,686,106
Moisture content (M), % (nominal)		6.5	6.5	6.5
Number of transfers		1	1	1
General/ Site Characteristics				
Mean wind speed, mph	Daily	11.0	11.0	11.0
	Annual	6.9	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35
Emission Control Data				
Emission control method		Fog type dust suppressant, enclosed building	Fog type dust suppressant, enclosed building	Fog type dust suppressant, enclosed building
Emission control removal efficiency, %		95	95	95
Emission Factor (EF) Equations				
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U / 5)^{1.3}$/$[(M / 2)^{1.4}]$			
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]			
Calculated PM Emission Factor (EF)				
Uncontrolled EF, lb/ton	Short term	0.001281	0.001281	0.001281
	Annual	0.000699	0.000699	0.000699
Controlled EF, lb/ton	Short term	0.000064	0.000064	0.000064
	Annual	0.000035	0.000035	0.000035
Calculated PM10 Emission Factor (EF)				
Uncontrolled EF, lb/ton	Short term	0.000606	0.000606	0.000606
	Annual	0.000330	0.000330	0.000330
Controlled EF, lb/ton	Short term	0.000030	0.000030	0.000030
	Annual	0.000017	0.000017	0.000017
Estimated Emission Rate (ER)				
PM ER lb/hr (daily basis)		0.012	0.012	0.012
TPY		0.029	0.029	0.029
PM10 ER lb/hr (daily basis)		0.006	0.006	0.006
TPY		0.014	0.014	0.014

Source. USEPA, 2006, AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

TABLE A-6
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE LIMESTONE HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

		Operations				
Parameters		**Limestone Handling TP-54** **Transfer limestone from Car Bottom Dumper to Limestone Unloading Hoppers**	**Limestone Handling TP-55** **Transfer limestone from Unloading Hopper to Belt Feeders to Conv. L-1**	**Limestone Handling TP-56** **Transfer limestone from Conv. L-1 Telescopic Chute to Active Limestone Stockout Pile**	**Limestone Handling TP-61** **Transfer limestone from Reclaim Hopper to Reclaim Belt Feeder**	**Limestone Handling TP-62** **Transfer limestone from Reclaim Belt feeder to Conv. L-2**
Emission Point/Area		TP-54	EP-68	Limestone Active Stockout Pile (No. 19)	Limestone Active Stockout Pile (No. 19)	Limestone Active Stockout Pile (No. 19)
Operational Data						
Activity, hours	Daily	1.4	1.4	1.4	3.4	3.4
days	Annual	365	365	365	365	365
Material Handling Data						
Material type		Limestone	Limestone	Limestone	Limestone	Limestone
Material throughput, ton/hr (design)	Hourly	1,000	1,000	1,000	400	400
ton/day	Daily	1,369	1,369	1,369	1,369	1,369
ton/yr	Annual	499,677	499,677	499,677	499,677	499,677
Moisture content (M), % (nominal)		2.0	2.0	2.0	2.0	2.0
Number of transfers		1	1	1	1	1
General/ Site Characteristics						
Mean wind speed, mph	Daily	6.9	6.9	6.9	6.9	6.9
	Annual	11.0	11.0	11.0	11.0	11.0
Particle size multiplier, PM (k)		0.74	0.74	0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35	0.35	0.35
Emission Control Data						
Emission control method		Watering and underground drop	Dust suppression, below grade	Dust suppression, roof building, telescopic chute	Enclosed loading skirtboard	Enclosed loading skirtboard
Emission control removal efficiency, %		90	90	90	50	50
Emission Factor (EF) Equations						
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U/5)^{1.3}$/[$(M/2)^{1.4}$]					
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]					
Calculated PM Emission Factor (EF)						
Uncontrolled EF, lb/ton	Short term	0.00360	0.00360	0.00360	0.00360	0.00360
	Annual	0.00660	0.00660	0.00660	0.00660	0.00660
Controlled EF, lb/ton	Short term	0.000360	0.000360	0.000360	0.001800	0.001800
	Annual	0.000660	0.000660	0.000660	0.003300	0.003300
Calculated PM10 Emission Factor (EF)						
Uncontrolled EF, lb/ton	Short term	0.00170	0.00170	0.00170	0.00170	0.00170
	Annual	0.00312	0.00312	0.00312	0.00312	0.00312
Controlled EF, lb/ton	Short term	0.000170	0.000170	0.000170	0.000851	0.000851
	Annual	0.000312	0.000312	0.000312	0.001561	0.001561
Estimated Emission Rate (ER)						
PM ER	lb/hr (daily basis)	0.021	0.021	0.021	0.103	0.103
	TPY	0.165	0.165	0.165	0.824	0.824
PM10 ER	lb/hr (daily basis)	0.010	0.010	0.010	0.049	0.049
	TPY	0.078	0.078	0.078	0.390	0.390

Source: USEPA, 2006; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles

TABLE A-7
IMATION OF PM EMISSION FACTORS AND RATES FOR THE FLY ASH AND BOTTOM ASH HANDLING SYSTEMS FROM BATCH/CONTINUOUS DROP OPERATI AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

		Operations			
		Fly Ash Handling TP-71/TP-71A	**Fly Ash Handling TP-69/TP-69A**	**Bottom Ash Handling TP-73**	**Bottom Ash Handling TP-76**
Parameters		**Transfer Unit 1 Fly Ash from Silo to Unloader to Trucks uisng Pug Mill or Equivalent**	**Transfer Unit 2 Fly Ash from Silo to Unloader to Trucks uisng Pug Mill or Equivalent**	**Transfer Bottom Ash from Submerged Drag Chain Conveyor to Bottom Ash Storage Bunker Unit 1**	**Transfer Bottom Ash from Submerged Drag Chain Conveyor to Bottom Ash Storage Bunker Unit 2**
Emission Point		Fly Ash Silo Area	Fly Ash Silo Area	Near Boiler Bldg #1	Near Boiler Bldg #2
Operational Data					
Trucks- number	Per day	58	58	15	15
number	Day/week	5	5	5	5
truck capacity	tons	20	20	20	20
Activity, hours	Daily	18	18	18	24
days	Annual	260	260	260	260
Material Handling Data					
Material type		Fly ash	Fly ash	Bottom Ash	Bottom Ash
Material throughput, ton/hr (design)	Hourly	48	48	12	12.1
ton/day	Daily	1,161	1,161	291	291
ton/yr	Annual	423,687	423,687	106,065	106,065
Moisture content (M), % (nominal)		20	20	20	20
Number of transfers		2	2	5	5
General/ Site Characteristics					
Mean wind speed, mph	Daily	11.0	11.0	11.0	11.0
	Annual	6.9	6.9	6.9	6.9
Particle size multiplier, PM (k)		0.74	0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35	0.35
Emission Control Data					
Emission control method		High moisture content (included in emission factor)	High moisture content (included in emission factor)	High moisture content (included in emission factor)	High moisture content (included in emission factor)
Emission control removal efficiency, %		0	0	0	0
Emission Factor (EF) Equations					
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = $k \times (0.0032) \times (U / 5)^{1.3})/[(M / 2)^{1.4}]$				
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.000263	0.000263	0.000263	0.000263
	Annual	0.000143	0.000143	0.000143	0.000143
Controlled EF, lb/ton	Short term	0.000263	0.000263	0.000263	0.000263
	Annual	0.000143	0.000143	0.000143	0.000143
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb/ton	Short term	0.000124	0.000124	0.000124	0.000124
	Annual	0.000068	0.000068	0.000068	0.000068
Controlled EF, lb/ton	Short term	0.000124	0.000124	0.000124	0.000124
	Annual	0.000068	0.000068	0.000068	0.000068
Estimated Emission Rate (ER)					
PM ER	lb/hr (daily basis)	0.0254	0.0254	0.0159	0.0159
	TPY	0.0607	0.0607	0.0380	0.0380
PM10 ER	lb/hr (daily basis)	0.0120	0.0120	0.0075	0.0075
	TPY	0.0287	0.0287	0.0180	0.0180

Source: USEPA, 1995; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles

TABLE A-8
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR THE GYPSUM HANDLING SYSTEM FROM BATCH/CONTINUOUS DROP OPERATIONS AT TRANSFER POINTS (NOT ASSOCIATED WITH SURGE BIN VENT FILTER)
PROJECT: FPL GLADES POWER PARK

		Operations				
		Gypsum Handling TP-79	**Gypsum Handling TP-81**	**Gypsum Handling TP-82**	**Gypsum Handling TP-83**	**Gypsum Handling TP-87**
Parameters		**Transfer Gypsum from Dewatering Bldg Conveyor G-1**	**Transfer Gypsum from Dewatering Bldg Conveyor G-3**	**Transfer Gypsum from Unit 1 Storage to Trucks to ByProduct Storage**	**Transfer Gypsum from Unit 2 Storage to Trucks to ByProduct Storage**	**Transfer Gypsum to Belt Conveyors for Rail Loading**
Emission Point/Area		Unit 1	Unit 2	Unit 1	Unit 2	
Operational Data						
Activity, hours	Daily	24	24	24	24.0	6
days	Annual	365	365	365	365	365
Material Handling Data						
Material type		Gypsum	Gypsum	Gypsum	Gypsum	Gypsum
Material throughput, ton/hr (design)	Hourly	80.0	80.0	80.0	80	400
ton/day	Daily	1,202	1,202	1,202	1,202	2,403
ton/yr	Annual	438,580	438,580	438,580	438,580	877,160
Moisture content (M), % (nominal)		10	10	10	10	10
Number of transfers		1	1	1	1	1
General/ Site Characteristics						
Mean wind speed, mph	Daily	6.9	6.9	6.9	6.9	6.9
	Annual	11.0	11.0	11.0	11.0	11.0
Particle size multiplier, PM (k)		0.74	0.74	0.74	0.74	0.74
Particle size multiplier, PM10 (k)		0.35	0.35	0.35	0.35	0.35
Emission Control Data						
Emission control method		High moisture content (included in emission factor)	High moisture content (included in emission factor)	High moisture content (included in emission factor)	High moisture content (included in emission factor)	High moisture content (included in emission factor)
Emission control removal efficiency, %		0	0	0	0	0
Emission Factor (EF) Equations						
Uncontrolled EF (UEF) Equation	UEF (lb/ton) = k x (0.0032) x $(U/5)^{1.3}$ $[(M/2)^{1.4}]$					
Controlled EF (CEF) Equation	CEF (lb/ton) = UEF (lb/ton) x [100% - Removal efficiency (%)]					
Calculated PM Emission Factor (EF)						
Uncontrolled EF, lb/ton	Short term	0.000378	0.000378	0.000378	0.000378	0.000378
	Annual	0.000693	0.000693	0.000693	0.000693	0.000693
Controlled EF, lb/ton	Short term	0.000378	0.000378	0.000378	0.000378	0.000378
	Annual	0.000693	0.000693	0.000693	0.000693	0.000693
Calculated PM10 Emission Factor (EF)						
Uncontrolled EF, lb/ton	Short term	0.000179	0.000179	0.000179	0.000179	0.000179
	Annual	0.000328	0.000328	0.000328	0.000328	0.000328
Controlled EF, lb/ton	Short term	0.000179	0.000179	0.000179	0.000179	0.000179
	Annual	0.000328	0.000328	0.000328	0.000328	0.000328
Estimated Emission Rate (ER)						
PM ER lb/hr (daily basis)		0.019	0.019	0.019	0.019	0.038
TPY		0.152	0.152	0.152	0.152	0.304
PM10 ER lb/hr (daily basis)		0.009	0.009	0.009	0.009	0.018
TPY		0.072	0.072	0.072	0.072	0.144

Source: USEPA, 1995; AP-42, Section 13.2.4 for Aggregate Handling and Storage Piles.

TABLE A-9
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR WIND EROSION FROM ACTIVE STORAGE PILES
PROJECT: FPL GLADES POWER PARK

		Operations			
Parameters		**Coal handling F-6 Fuel A Active Stockout Pile-Fuel A**	**Coal handling F-6 Pet Coke Active Stockout Pile-Pet Coke**	**Coal handling F-6 Fuel B Active Stockout Pile-Fuel B**	**Coal handling F-14 Inactive Coal Storage Stockout Pile**
Emission Point/Area		Active Coal Stockout Pile (No. 02)	Active Coal Stockout Pile (No. 02)	Active Coal Stockout Pile (No. 02)	Active Coal Stockout Pile (No. 03)
Storage Pile Data					
Material Type		Coal	Pet Coke	Coal	Coal
Pile Description (shape)		Rectangular	Rectangular	Rectangular	Rectangular
Average Storage (ton)					
Average Pile Height (ft)		72	72	72	72
Average Pile Length (ft)		143	143	143	713
Average Pile Width (ft)		143	143	143	713
Size, ft^2		20,492	20,492	20,492	509,071
Size, acres		0.47	0.47	0.47	11.70
General/ Site Characteristics					
Days of precipitation greater than or equal to 0.01 inch (p)	Short term	0	0	0	0
	Annual	113	113	113	113
Time (%) that unobstructed wind speed exceeds 5.4 m/s at mean pile height (f)	Short term	75	75	75	75
	Annual	35	35	35	35
Silt content (s), %		2.2	2.2	2.2	2.2
Particle size multiplier, PM (k)		1.00	1.00	1.00	1.00
Particle size multiplier, PM10 (k)		0.50	0.50	0.50	0.50
Emission Control Data					
Emission control method		None	None	None	Crusting Agent
Emission control removal efficiency, %		0	0	0	99
Emission Factor (EF) Equation					
Uncontrolled EF (UEF) Equation	UEF (lb/day/acre) = k x 1.7 x (s/1.5) x ((365 - p)/235) x (f/15)				
Controlled (Final) EF (CEF) Equation	CEF (lb/day/acre) = UEF (lb/day/acre) x (100 - Removal efficiency (%))				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/day/acre	Short term	19.36	19.36	19.36	19.36
	Annual	6.24	6.24	6.24	6.24
Controlled EF, lb/day/acre	Short term	19.36	19.36	19.36	0.19
	Annual	6.24	6.24	6.24	0.06
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb/day/acre	Short term	6.23	6.23	6.23	6.23
	Annual	2.01	2.01	2.01	2.01
Controlled EF, lb/day/acre	Short term	6.23	6.23	6.23	0.06
	Annual	2.01	2.01	2.01	0.02
Estimated Emission Rate (ER)					
PM ER	lb/hr (daily basis)	0.38	0.38	0.38	0.09
	TPY	0.54	0.54	0.54	0.13
PM10 ER	lb/hr (daily basis)	0.12	0.12	0.12	0.03
	TPY	0.17	0.17	0.17	0.04

Source: USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures. Section 2.3.1.3.3. Wind Emissions from Continuously Active Piles)

TABLE A-9
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR WIND EROSION FROM ACTIVE STORAGE PILES
PROJECT: FPL GLADES POWER PARK

Parameters		Operations			
		Coal Handling F-13 Inactive Stockout Pile	**Limestone Handling F-58 Active Limestone Stockout Pile**	**Limestone Handling F-59 Active Limestone Stockout Pile**	**Bottom Ash Handling F-74 and F-77 Bottom Ash Storage Pile-Unit 1 and 2**
Emission Point/Area		Inactive Stockout Pile	Limestone Active Stockout Pile (6,600 tons)	Limestone Inactive Stockout Pile (66,500 tons)	Near Boiler Bldg #1
Storage Pile Data					
Material Type		Coal	Limestone	Limestone	Bottom ash
Pile Description (shape)		Circular	Circular	Circular	Rectangular
Average Storage (ton)					
Average Pile Height (ft)		72	30	50	15
Average Pile Length or Diameter(ft)		121	65	159	20
Average Pile Width (ft)		NA	NA	NA	20
Size, ft^2		11,526	3,300	19,950	400
Size, acres		0.26	0.08	0.46	0.01
General/ Site Characteristics					
Days of precipitation greater than or equal to 0.01 inch (p)	Short term	0	0	0	0
	Annual	113	113	113	113
Time (%) that unobstructed wind speed exceeds 5.4 m/s at mean pile height (f)	Short term	75	75	75	75
	Annual	35	35	35	35
Silt content (s), %		2.2	2.2	2.2	2.2
Particle size multiplier, PM (k)		1.00	1.00	1.00	1.00
Particle size multiplier, PM10 (k)		0.50	0.50	0.50	0.50
Emission Control Data					
Emission control method		None	Partially enclosed	Crusting Agent	High moisture content (20%) and Partially Enclosed
Emission control removal efficiency, %		0	70	99	90
Emission Factor (EF) Equation					
Uncontrolled EF (UEF) Equation	UEF (lb/day/acre) = k x 1.7 x (s/1.5) x ((365 - p)/235) x (f/15)				
Controlled (Final) EF (CEF) Equation	CEF (lb/day/acre) = UEF (lb/day/acre) x (100 - Removal efficiency (%))				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/day/acre	Short term	19.36	19.36	19.36	19.36
	Annual	6.24	6.24	6.24	6.24
Controlled EF, lb/day/acre	Short term	19.36	5.81	0.19	1.94
	Annual	6.24	1.87	0.06	0.62
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb day/acre	Short term	6.23	6.23	6.23	6.23
	Annual	2.01	2.01	2.01	2.01
Controlled EF, lb/day/acre	Short term	6.23	1.87	0.06	0.62
	Annual	2.01	0.60	0.02	0.20
Estimated Emission Rate (ER)					
PM ER lb/hr (daily basis)		0.21	0.02	0.00	0.0007
TPY		0.30	0.026	0.005	0.0010
PM10 ER lb/hr (daily basis)		0.07	0.006	0.001	0.0002
TPY		0.10	0.008	0.002	0.0003

Source: USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures, Section 2.3.1.3.3, Wind Emissions from Continuously Active Piles)

TABLE A-9
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR WIND EROSION FROM ACTIVE STORAGE PILES
PROJECT: FPL GLADES POWER PARK

		Operations			
Parameters		**Bottom Ash Handling** **F-83** **Units 1 and 2;** **Stockout for Sale**	**Gypsum handling** **F-84** **Gypsum Stockout Pile** **Unit 1**	**Gypsum handling** **F-85** **Gypsum Stockout Pile** **Unit 2**	**Byproduct handling** **F-91** **Byproduct Storage Area**
Emission Point/Area		Near Boiler Bldg #1	Gypsum Storage Shed (26)	Gypsum Storage Shed (26)	Byproduct Storage Area
Storage Pile Data					
Material Type		Bottom ash	Gypsum	Gypsum	Byproduct
Pile Description (shape)		Rectangular	Circular	Circular	Rectangular
Average Storage (ton)					
Average Pile Height (ft)		15	15	15	60
Average Pile Length or Diameter (ft)		45	110.65	110.65	933
Average Pile Width (ft)		45	NA	NA	933
Size, ft^2		2,000	111	9,617	870,000
Size, acres		0.05	0.003	0.003	20
General/ Site Characteristics					
Days of precipitation greater than or equal to 0.01 inch (p)	Short term	0	0	0	0
	Annual	113	113	113	113
Time (%) that unobstructed wind speed exceeds 5.4 m/s at mean pile height (f)	Short term	75	75	75	75
	Annual	35	35	35	35
Silt content (s), %		2.2	2.2	2.2	2.2
Particle size multiplier, PM (k)		1.00	1.00	1.00	1.00
Particle size multiplier, PM10 (k)		0.50	0.50	0.50	0.50
Emission Control Data					
Emission control method		High moisture content (20%)	None	None	High moisture content, watering as needed and cover
Emission control removal efficiency, %		70	0	0	95
Emission Factor (EF) Equation					
Uncontrolled EF (UEF) Equation	UEF (lb/day/acre) = k x 1.7 x (s/1.5) x ((365 - p)/235) x (f/15)				
Controlled (Final) EF (CEF) Equation	CEF (lb/day/acre) = UEF (lb/day/acre) x (100 - Removal efficiency (%))				
Calculated PM Emission Factor (EF)					
Uncontrolled EF, lb/day/acre	Short term	19.36	19.36	19.36	19.36
	Annual	6.24	6.24	6.24	6.24
Controlled EF, lb/day/acre	Short term	5.81	19.36	19.36	0.97
	Annual	1.87	6.24	6.24	0.31
Calculated PM10 Emission Factor (EF)					
Uncontrolled EF, lb/day/acre	Short term	6.23	6.23	6.23	6.23
	Annual	2.01	2.01	2.01	2.01
Controlled EF, lb/day/acre	Short term	1.87	6.23	6.23	0.31
	Annual	0.60	2.01	2.01	0.10
Estimated Emission Rate (ER)					
PM ER	lb/hr (daily basis)	0.0111	0.00	0.00	0.8
	TPY	0.0157	0.003	0.003	1.1
PM10 ER	lb/hr (daily basis)	0.0036	0.001	0.001	0.3
	TPY	0.0051	0.001	0.001	0.4

Source: USEPA, 1992 (Fugitive Dust Background and Technical Information Document for Best Available Control Measures, Section 2.3.1.3.3, Wind Emissions from Continuously Active Piles)

TABLE A-10
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR BULLDOZERS AND FRONT END LOADERS ON UNPAVED ROADS
PROJECT: FPL GLADES POWER PARK

		Operations	
		Coal Handling	**Coal Handling**
		F-12	**F-28**
Parameters		**Bulldozing from Stackout Pile to Inactive Storage Pile**	**Bulldozing from Stackout or Inactive Storage Piles**
Emission Point/Area		Inactive Coal Storage	Inactive Coal Storage
Vehicle Data			
Vehicle weight (W), 70 ton loaded	Loaded	70	0
	Unloaded	50	0
	Average	60	0
Material throughput, ton	Hourly	4,000	4,000
Operating time, hours	Daily	Occasional	Occasional
days	Annual	37	37
Basis for vehicle miles traveled (VMT)			
Number of vehicles	Daily	3	3
	Annual	1,277	1,277
Distance (miles) traveled/vehicle/route	Per trip	0.038	0.038
VMT (no vehicles x miles traveled per trip)	Daily	3	3
	Annual	1,277	1,277
General/ Site Characteristics			
Days of precipitation greater than or equal to 0.254 mm (p)	Short-term	0	0
	Annual	113	113
Silt content (s), %		2.2	2.2
Particle size multiplier, PM (k)		4.9	4.9
PM_{10} (k)		1.5	1.5
Coefficients for silt content- PM	a	0.7	0.7
	b	0.45	0.45
Coefficients for silt content- PM10	a	0.9	0.9
	b	0.45	0.45
Emission Control Data			
Emission control method		Watering as needed	Watering as needed
Emission control removal efficiency, %		60	60
Emission Factor (EF) Equation			
Uncontrolled EF (UEF) Equation	UEF(lb/VMT) = k x $(s/12)^a$ x $(W)/3)^b$ x [(365 - p)/365]		
Controlled EF (CEF) Equation	CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%))		
Calculated PM Emission Factor (EF)			
Uncontrolled EF, lb/VMT	Short term	5.75	0.00
	Annual	3.97	0.00
Controlled EF, lb/VMT	Short term	2.30	0.00
	Annual	1.59	0.00
Calculated PM10 Emission Factor (EF)			
Uncontrolled EF, lb/VMT	Short term	1.25	0.00
	Annual	0.87	0.00
Controlled EF, lb/VMT	Short Term	0.50	0.00
	Annual	0.35	0.00
Estimated Emission Rate (ER)			
PM ER lb/hr (based on daily rate)		0.34	0.00
TPY		1.01	0.00
PM10 ER lb/hr (based on daily rate)		0.07	0.00
TPY		0.22	0.00

Source: USEPA, 2006 (AP-42, Section 13.2.2 Unpaved Roads).

TABLE A-10
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR BULLDOZERS AND FRONT END LOADERS ON UNPAVED ROADS
PROJECT: FPL GLADES POWER PARK

		Operations		
		Limestone Handling	**Limestone Handling**	**Bottom Ash Handling**
		F-57	**F-60**	**F-75**
Parameters		**Bulldozing from Active Limestone Stockout Pile to Inactive Limestone Storage Pile**	**Bulldozing from Active or Inactive Limestone Piles to Dozer Reclaim Hopper**	**Front-end Loader- Loading of Bottom Ash into Truck- Unit 1**
Emission Point/Area		Limestone Active Stockout Pile (No. 19)	Limestone Active Stockout Pile (No. 19)	Near Boiler Bldg #1
Vehicle Data				
Vehicle weight (W), ton	Loaded	70	70	70
	Unloaded	50	50	50
	Average	60	60	60
Material throughput, ton	Hourly	400	400	80
Operating time, hours	Daily	Occasional	8.00	8
days	Annual	24	365	365
Basis for vehicle miles traveled (VMT)				
Number of vehicles	Daily	1	1	1
	Annual	24	365	365
Distance (miles) traveled/vehicle/route	Per trip	1	0.019	0.038
VMT (no. vehicles x miles traveled per trip)	Daily	1.00	1.30	0.55
	Annual	24	473	201
General/ Site Characteristics				
Days of precipitation greater than or equal to 0.254 mm (p)	Short-term	0	0	0
	Annual	113	113	113
Silt content (s), %		2.2	2.2	2.2
Particle size multiplier, PM (k)		4.9	4.9	4.9
PM$_{10}$ (k)		1.5	1.5	1.5
Coefficients for silt content- PM	a	0.7	0.7	0.7
	b	0.45	0.45	0.45
Coefficients for silt content- PM10	a	0.9	0.9	0.9
	b	0.45	0.45	0.45
Emission Control Data				
Emission control method		None	None	None
Emission control removal efficiency, %		0	0	0
Emission Factor (EF) Equation				
Uncontrolled EF (UEF) Equation	UEF(lb/VMT) = k x $(s/12)^a$ x $(W)/3)^b$ x [(365 - p)/365]			
Controlled EF (CEF) Equation	CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%))			
Calculated PM Emission Factor (EF)				
Uncontrolled EF, lb/VMT	Short term	5.75	5.75	5.75
	Annual	3.97	3.97	3.97
Controlled EF, lb/VMT	Short term	5.75	5.75	5.75
	Annual	3.97	3.97	3.97
Calculated PM10 Emission Factor (EF)				
Uncontrolled EF, lb/VMT	Short term	1.25	1.25	1.25
	Annual	0.87	0.87	0.87
Controlled EF, lb/VMT	Short Term	1.25	1.25	1.25
	Annual	0.87	0.87	0.87
Estimated Emission Rate (ER)				
PM ER lb/hr (based on daily rate)		0.24	0.31	0.13
TPY		0.05	0.94	0.40
PM10 ER lb/hr (based on daily rate)		0.05	0.07	0.03
TPY		0.01	0.20	0.09

Source: USEPA, 2006 (AP-42, Section 13.2.2 Unpaved Roads).

TABLE A-10
ESTIMATION OF PM EMISSION FACTORS AND RATES FOR BULLDOZERS AND FRONT END LOADERS ON UNPAVED ROADS
PROJECT: FPL GLADES POWER PARK

		Operations	
Parameters		**Bottom ash handling** **F-76** **Front end loader- loading of Bottom Ash into truck- Unit 2**	**Byproduct storage handling** **F-90** **Bulldozing and Compacting**
Emission Point/Area		Near Boiler Bldg #2	Byproduct Storage Area
Vehicle Data			
Vehicle weight (W), ton	Loaded	70	70
	Unloaded	50	50
	Average	60	60
Material throughput, ton	Hourly	80	-
Operating time, hours	Daily	1	2
days	Annual	365	365
Basis for vehicle miles traveled (VMT)			
Number of vehicles	Daily	1	2
	Annual	365	730
Distance (miles) traveled/vehicle/route	Per trip	0.038	0.074
VMT (no. vehicles x miles traveled per trip)	Daily	0.550	20
	Annual	201	7,205
General/ Site Characteristics			
Days of precipitation greater than or equal to 0.254 mm (p)	Short-term	0	0
	Annual	113	113
Silt content (s), %		2.2	2.2
Particle size multiplier, PM (k)		4.9	4.9
PM_{10} (k)		1.5	1.5
Coefficients for silt content- PM	a	0.7	0.7
	b	0.45	0.45
Coefficients for silt content- PM10	a	0.9	0.9
	b	0.45	0.45
Emission Control Data			
Emission control method		High moisture content (20%)	High moisture content and watering as needed
Emission control removal efficiency, %		90	90
Emission Factor (EF) Equation			
Uncontrolled EF (UEF) Equation	UEF(lb/VMT) = $k \times (s/12)^a \times (W)/3)^b \times [(365 - p)/365]$		
Controlled EF (CEF) Equation	CEF(lb/VMT) = UEF (lb/VMT) x (100 - Removal efficiency (%))		
Calculated PM Emission Factor (EF)			
Uncontrolled EF, lb/VMT	Short term	5.75	5.75
	Annual	3.97	3.97
Controlled EF, lb/VMT	Short term	0.58	0.58
	Annual	0.40	0.40
Calculated PM_{10} Emission Factor (EF)			
Uncontrolled EF, lb/VMT	Short term	1.25	1.25
	Annual	0.87	0.87
Controlled EF, lb/VMT	Short Term	0.13	0.13
	Annual	0.09	0.09
Estimated Emission Rate (ER)			
PM ER lb/hr (based on daily rate)		0.01	0.47
TPY		0.04	1.43
PM10 ER lb/hr (based on daily rate)		0.00	0.10
TPY		0.01	0.31

Source: USEPA, 2006 (AP-42, Section 13.2.2 Unpaved Roads).

TABLE A-11
ESTIMATION OF DAILY PM EMISSION FACTORS AND RATES FOR VEHICLE TRAFFIC ON PAVED ROADS
PROJECT: FPL GLADES POWER PARK

General Data		By Products Storage F-95	Vehicles F-95	Combined Vehicles
Throughput Data				
Operation days (N)	Annual	365	365	365
Vehicle Data				
Number of vehicles	Annual	96,833	65,700	162,533
	Daily	265 a	180	445
Distance (miles) travelled/ vehicle/ route	Per trip	4.18	4.18	4 18
VMT (no. vehicles x miles travelled)	Annual	404,939	274,745	679,684
	Daily	1,109.4	752.7	1,862.1
Vehicle weight (W), ton	Loaded	32.5	3	
	Unloaded	12.5	3	
	Average- Annual	22.5	3	14.6
	Daily	22.5	3	14.6
General/ Site Characteristics				
Days of precipitation greater than or equal to 0.254 mm (P)	Daily	0	0	0
	Annual	113	113	113
Silt Loading (sL), g/m^2		1.0	1.0	1.0
Particle size multiplier, PM (k)		0.082	0.082	0.082
PM_{10} (k)		0.016	0.016	0.016
Emission Factor Fleet Exhaust (C), lb/VMT		0.00047	0.00047	0.00047
Emission Control Data				
Emission control method		Vacuum Sweeping/Watering	Vacuum Sweeping/Watering	Vacuum Sweeping/Watering
Emission control removal efficiency, %		90	90	90
Emission Factor (EF) Equation (Equations 1 & 2, daily basis, AP-42, Section 13.2.1.3)				
Uncontrolled EF (UEF) Equation - PM	$\mathrm{UEF(lb/VMT)} = [k \times \{(sL/2)^{0.65} \times (W(\mathrm{ton, ave})/3)^{1.5}\}-C\} (1-P/4N)$			
PM_{10}	$\mathrm{UEF(lb/VMT)} = [k \times \{(sL/2)^{0.65} \times (W(\mathrm{ton, ave})/3)^{1.5}\}-C] (1-P/4N)$			
Controlled (Final) EF (CEF) Equation	$\mathrm{CEF(lb/VMT)} = \mathrm{UEF\ (lb/VMT)} \times (100 - \mathrm{Removal\ efficiency\ (\%)})$			
Calculated PM Emission Factor (EF)				
Uncontrolled EF, lb/VMT	Daily			0.56
	Annual			0 52
Controlled (Final) EF, lb/VMT	Daily			0.06
	Annual			0.05
Calculated PM_{10} Emission Factor (EF)				
Uncontrolled EF, lb/VMT	Daily			0.109
	Annual			0.101
Controlled (Final) EF, lb/VMT	Daily			0.011
	Annual			0.010
Estimated Emission Rate (ER)				
PM Emission Rate (lb/hr)	Daily			4.4
PM Emission Rate (TPY)	Annual			17.6
PM_{10} Emission Rate (lb/hr)	Daily			0.85
PM_{10} Emission Rate (TPY)	Annual			3.42

Source: USEPA, 2003 (AP-42, Section 13.2.1, Paved Roads)

a Number of vehicles based on		
	1,936,664	tons byproducts
	96833.2	trips
	265	trips per day

TABLE A-12

INPUT DATA FOR MATERIALS HANDLING EMISSIONS ESTIMATES PROJECT: FPL GLADES POWER PARK

	Coal		Limestone		Fly Ash		Bottom Ash		Gypsum	
Material Handling Data										
Throughput, tons/year	6,744,425		499,677		847,374		212,129		877,160	
Moisture Content, %	6.45	a	2	a	20	a	20	a	10	a
Silt content (s), %	2.2	b	1.6	b	NA		NA		1.6	b
Meteorological Data										
Mean Wind Speed, mph, annual	6.9	c								
Mean Wind Speed, mph, daily	11	d								
Number of Days >0.01 in rain, P	113	e								
Frequency of Time wind >12 mph, F, %	13	f								

This table provides the material and meteorological data used in the emission calculations.
Other spreadsheets have the operating parameters for each area.

a Coal: average moisture; Limestone: assumed; Fly Ash and Bottom Ash (after plug mill wetting); Gypsume: Design.
b Coal and Limestone: AP-42 Table 13.2.4-1; Fly Ash and Bottom Ash: not required; Gypsum: assumed.
c 2005 Local Climatological Data for Fort Myers (7 years of record)
d 2001-2005 Fort Myers, 90% percentile daily average wind speed.
e 2005 Local Climatological Data for Fort Myers International Airport (30 years of record)
f 2001-2005 Fort Myers hourly wind speeds > 12 mph.

Sources: FPL, 2006; Golder, 2006.

TABLE A-12a
HIERARCHY OF CONTROL METHODS FOR MATERIAL HANDLING OPERATIONS
Project: FPL Glades Power Project

Control Method Used [1]	Control Efficiency	Description and Rationale
Underground enclosed building, or equivalent	99%	Enclosed with bag-type filter. Source underground in an enclosed space with low drops. See (2)
Enclosed Structure or Area	95%	Source enclosed with minimum openings for fugitive dust to escape
Water Sprays and enclosed on three sides	90%	60% for water spray and 75% for wind reduction for partial enclosure. See (2)
Water Sprays with Low Drops, or equivalent	90%	Low drop resulting in lower PM emissions coupled with water sprays
Telescoping chute with water sprays, or equivalent	75%	Moderate drop coupled with water sprays
Partial Enclosure with no control	70%	Low to moderate drop with some openings on at least two sides. See (2)
Open Enclosure with water sprays, or equivalent	60%	Water sprays (Based on 42% to 75% from EPA, 1992)
No control	0%	No control provided

Source: EPA, 1992; Golder, 2006.
(1) Based on proposed preliminary design for the barge and the land-based system.

EPA, 1992. Fugitive Dust Background Document and Technical Information Document for Best Available Control Measures.
OAQPS, EPA-450/2-92-004

(2) Reduction Based on Reducing Wind Speed

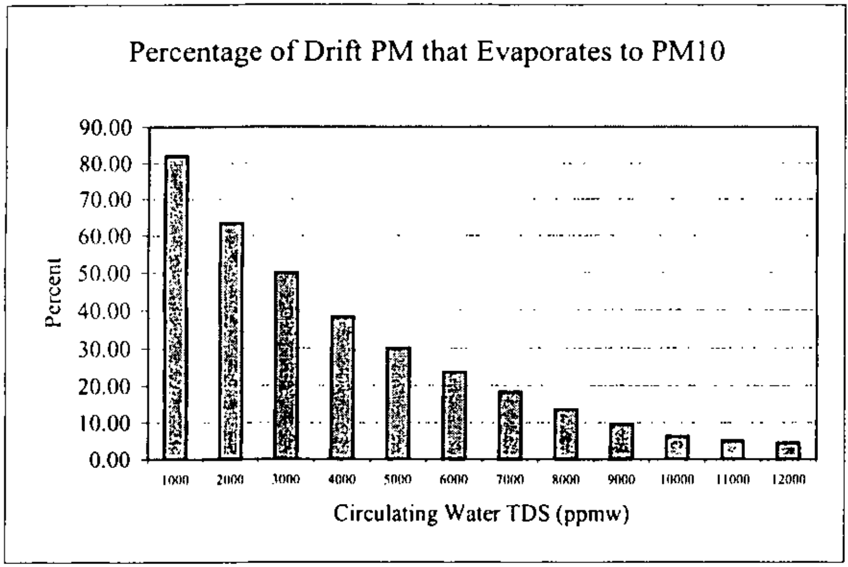
Wind Speed (U) (mph)	$(U/5)^{1.3}$	Reduction from 6.9 mph	Comment
6.9	1.520		Used for open source
6.5	1.406	7.47%	
6	1.267	16.61%	
5.5	1.132	25.53%	
5	1.000	34.21%	
4.5	0.872	42.63%	
4	0.748	50.78%	
3.5	0.629	58.62%	
3	0.515	66.13%	
2.5	0.406	73.28%	Used for partially enclosed source
2	0.304	80.01%	
1.5	0.209	86.25%	
1	0.123	91.88%	Used for enclosed (3-sided) source
0.5	0.050	96.70%	
0.25	0.020	98.66%	Used for totally enclosed source

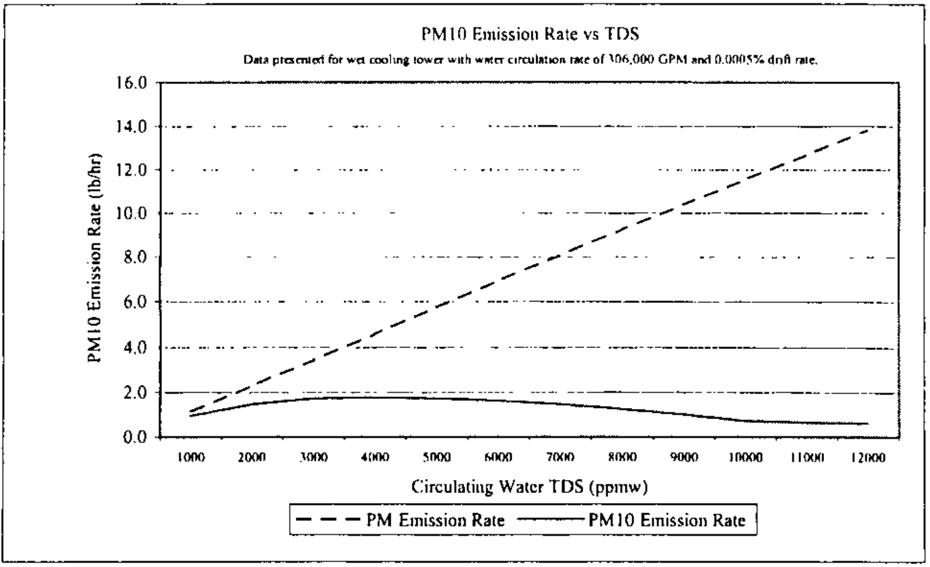
EMISSIONS FROM
COOLING TOWERS

TDS (ppmw)	PM Emission Rate (lb/hr)	Percent of Emissions < or = PM10 %	PM10 Emissions (lb/hr)
1000	1.153	82.04	0.946
2000	2.306	63.50	1.464
3000	3.459	50.00	1.730
4000	4.612	38.33	1.768
5000	5.765	29.97	1.728
6000	6.918	23.59	1.632
7000	8.071	18.20	1.469
8000	9.224	13.57	1.252
9000	10.378	9.65	1.001
10000	11.531	6.28	0.724
11000	12.684	5.11	0.648
12000	13.837	4.46	0.617
30000	34.592	0.76	0.263
89600	103.314	0.22	0.227

Tower Circulation Rate (GPM)	Drift Rate %
460,855	0.0005

Calculated PM10 % < or = PM10 %
82.04
63.50
50.00
38.33
29.97
23.59
18.20
13.57
9.65
6.28
5.11
4.46
0.76
0.22


Percentage of Drift PM that Evaporates to PM10


PM10 Emission Rate vs TDS

Data presented for wet cooling tower with water circulation rate of 306,000 GPM and 0.0005% drift rate.

TABLE CT-1
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 1000 ppmv)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-07	0.24	0.769	0.000
20	4188.8	4.19E-03	4.19E-06	1.90	1.538	0.196
30	14137.2	1.41E-02	1.41E-05	6.43	2.307	0.226
40	33510.3	3.35E-02	3.35E-05	15.23	3.076	0.514
50	65449.8	6.54E-02	6.54E-05	29.75	3.844	1.816
60	113097.3	1.13E-01	1.13E-04	51.41	4.613	5.702
70	179594.4	1.80E-01	1.80E-04	81.63	5.382	21.348
90	381703.5	3.82E-01	3.82E-04	173.50	6.920	49.812
110	696910.0	6.97E-01	6.97E-04	316.78	8.458	70.509
130	1150346.5	1.15E+00	1.15E-03	522.88	9.995	82.023
150	1767145.9	1.77E+00	1.77E-03	803.25	11.533	88.012
180	3053628.1	3.05E+00	3.05E-03	1388.01	13.840	91.032
210	4849048.3	4.85E+00	4.85E-03	2204.11	16.147	92.468
240	7238229.5	7.24E+00	7.24E-03	3290.10	18.453	94.091
270	10305994.7	1.03E+01	1.03E-02	4684.54	20.760	94.689
300	14137166.9	1.41E+01	1.41E-02	6425.98	23.066	96.288
350	22449297.5	2.24E+01	2.24E-02	10204.23	26.911	97.011
400	33510321.6	3.35E+01	3.35E-02	15231.96	30.755	98.340
450	47712938.4	4.77E+01	4.77E-02	21687.70	34.600	99.071
500	65449846.9	6.54E+01	6.54E-02	29749.93	38.444	99.071
600	113097335.5	1.13E+02	1.13E-01	51407.88	46.133	100.000

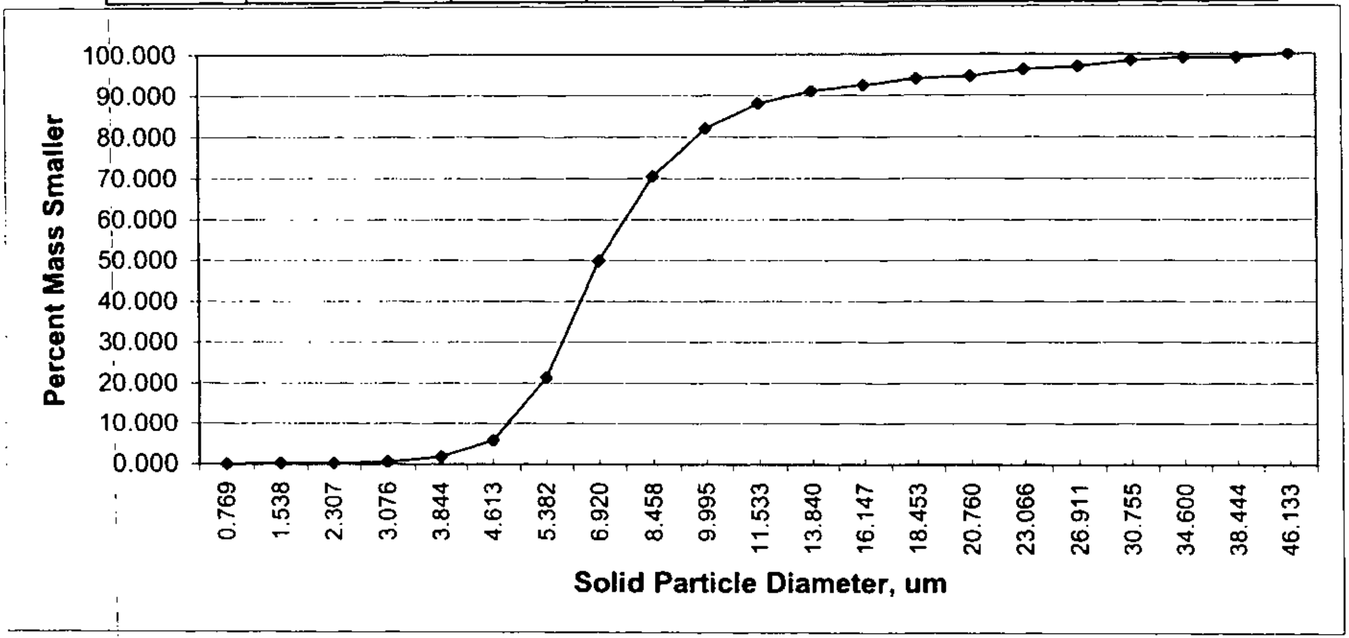


TABLE CT-2

RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 2000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.05E-06	0.48	0.969	0.000
20	4188.8	4.19E-03	8.38E-06	3.81	1.937	0.196
30	14137.2	1.41E-02	2.83E-05	12.85	2.906	0.226
40	33510.3	3.35E-02	6.70E-05	30.46	3.875	0.514
50	65449.8	6.54E-02	1.31E-04	59.50	4.844	1.816
60	113097.3	1.13E-01	2.26E-04	102.82	5.812	5.702
70	179594.4	1.80E-01	3.59E-04	163.27	6.781	21.348
90	381703.5	3.82E-01	7.63E-04	347.00	8.719	49.812
110	696910.0	6.97E-01	1.39E-03	633.55	10.656	70.509
130	1150346.5	1.15E+00	2.30E-03	1045.77	12.593	82.023
150	1767145.9	1.77E+00	3.53E-03	1606.50	14.531	88.012
180	3053628.1	3.05E+00	6.11E-03	2776.03	17.437	91.032
210	4849048.3	4.85E+00	9.70E-03	4408.23	20.343	92.468
240	7238229.5	7.24E+00	1.45E-02	6580.21	23.250	94.091
270	10305994.7	1.03E+01	2.06E-02	9369.09	26.156	94.689
300	14137166.9	1.41E+01	2.83E-02	12851.97	29.062	96.288
350	22449297.5	2.24E+01	4.49E-02	20408.45	33.906	97.011
400	33510321.6	3.35E+01	6.70E-02	30463.93	38.749	98.340
450	47712938.4	4.77E+01	9.54E-02	43375.40	43.593	99.071
500	65449846.9	6.54E+01	1.31E-01	59499.86	48.436	99.071
600	113097335.5	1.13E+02	2.26E-01	102815.76	58.124	100.000

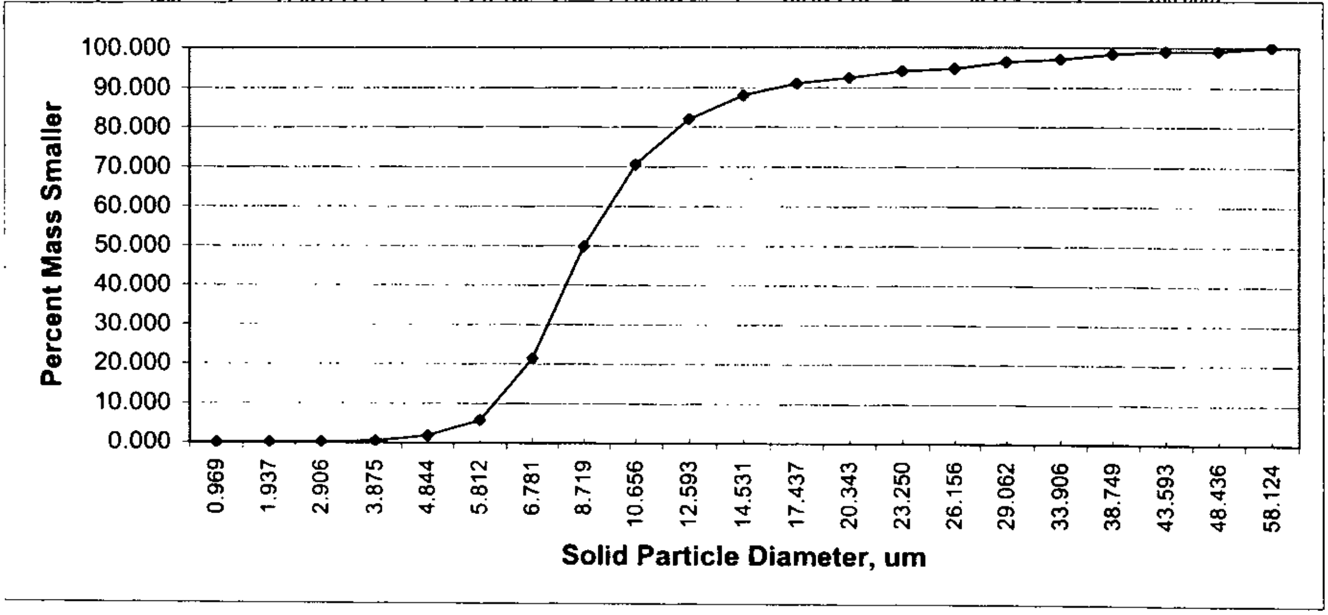


TABLE CT-3
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 3000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-06	0.71	1.109	0.000
20	4188.8	4.19E-03	1.26E-05	5.71	2.218	0.196
30	14137.2	1.41E-02	4.24E-05	19.28	3.327	0.226
40	33510.3	3.35E-02	1.01E-04	45.70	4.436	0.514
50	65449.8	6.54E-02	1.96E-04	89.25	5.545	1.816
60	113097.3	1.13E-01	3.39E-04	154.22	6.654	5.702
70	179594.4	1.80E-01	5.39E-04	244.90	7.762	21.348
90	381703.5	3.82E-01	1.15E-03	520.50	9.980	49.812
110	696910.0	6.97E-01	2.09E-03	950.33	12.198	70.509
130	1150346.5	1.15E+00	3.45E-03	1568.65	14.416	82.023
150	1767145.9	1.77E+00	5.30E-03	2409.74	16.634	88.012
180	3053628.1	3.05E+00	9.16E-03	4164.04	19.961	91.032
210	4849048.3	4.85E+00	1.45E-02	6612.34	23.287	92.468
240	7238229.5	7.24E+00	2.17E-02	9870.31	26.614	94.091
270	10305994.7	1.03E+01	3.09E-02	14053.63	29.941	94.689
300	14137166.9	1.41E+01	4.24E-02	19277.95	33.268	96.288
350	22449297.5	2.24E+01	6.73E-02	30612.68	38.812	97.011
400	33510321.6	3.35E+01	1.01E-01	45695.89	44.357	98.340
450	47712938.4	4.77E+01	1.43E-01	65063.10	49.901	99.071
500	65449846.9	6.54E+01	1.96E-01	89249.79	55.446	99.071
600	113097335.5	1.13E+02	3.39E-01	154223.64	66.535	100.000

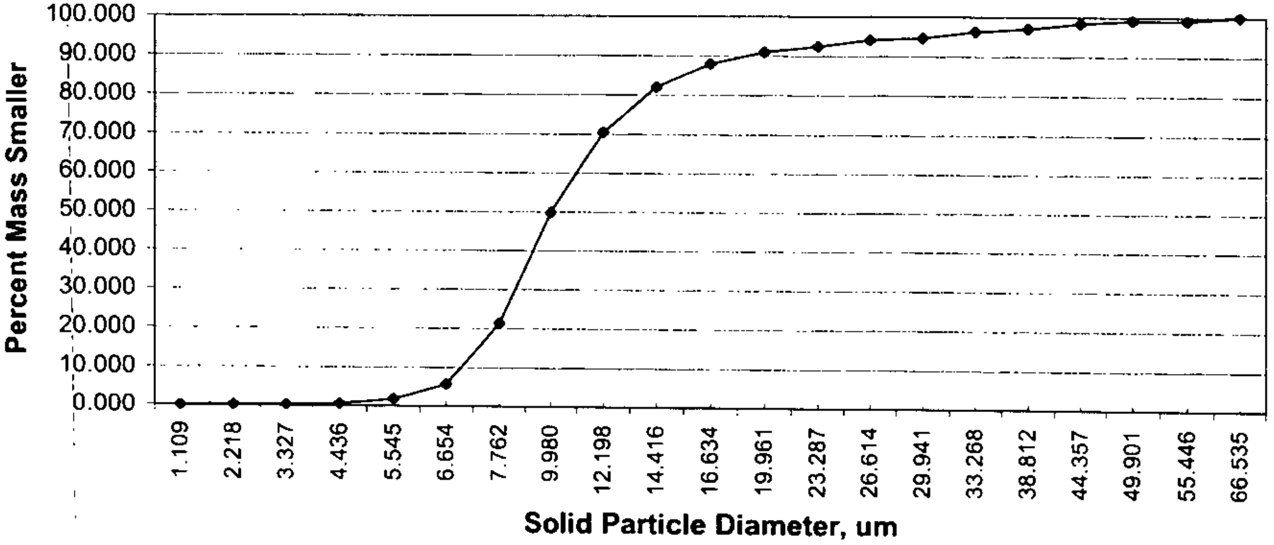


TABLE CT-4
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 4000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	2.09E-06	0.95	1.221	0.000
20	4188.8	4.19E-03	1.68E-05	7.62	2.441	0.196
30	14137.2	1.41E-02	5.65E-05	25.70	3.662	0.226
40	33510.3	3.35E-02	1.34E-04	60.93	4.882	0.514
50	65449.8	6.54E-02	2.62E-04	119.00	6.103	1.816
60	113097.3	1.13E-01	4.52E-04	205.63	7.323	5.702
70	179594.4	1.80E-01	7.18E-04	326.54	8.544	21.348
90	381703.5	3.82E-01	1.53E-03	694.01	10.985	49.812
110	696910.0	6.97E-01	2.79E-03	1267.11	13.426	70.509
130	1150346.5	1.15E+00	4.60E-03	2091.54	15.867	82.023
150	1767145.9	1.77E+00	7.07E-03	3212.99	18.308	88.012
180	3053628.1	3.05E+00	1.22E-02	5552.05	21.969	91.032
210	4849048.3	4.85E+00	1.94E-02	8816.45	25.631	92.468
240	7238229.5	7.24E+00	2.90E-02	13160.42	29.293	94.091
270	10305994.7	1.03E+01	4.12E-02	18738.17	32.954	94.689
300	14137166.9	1.41E+01	5.65E-02	25703.94	36.616	96.288
350	22449297.5	2.24E+01	8.98E-02	40816.90	42.718	97.011
400	33510321.6	3.35E+01	1.34E-01	60927.86	48.821	98.340
450	47712938.4	4.77E+01	1.91E-01	86750.80	54.924	99.071
500	65449846.9	6.54E+01	2.62E-01	118999.72	61.026	99.071
600	113097335.5	1.13E+02	4.52E-01	205631.52	73.231	100.000

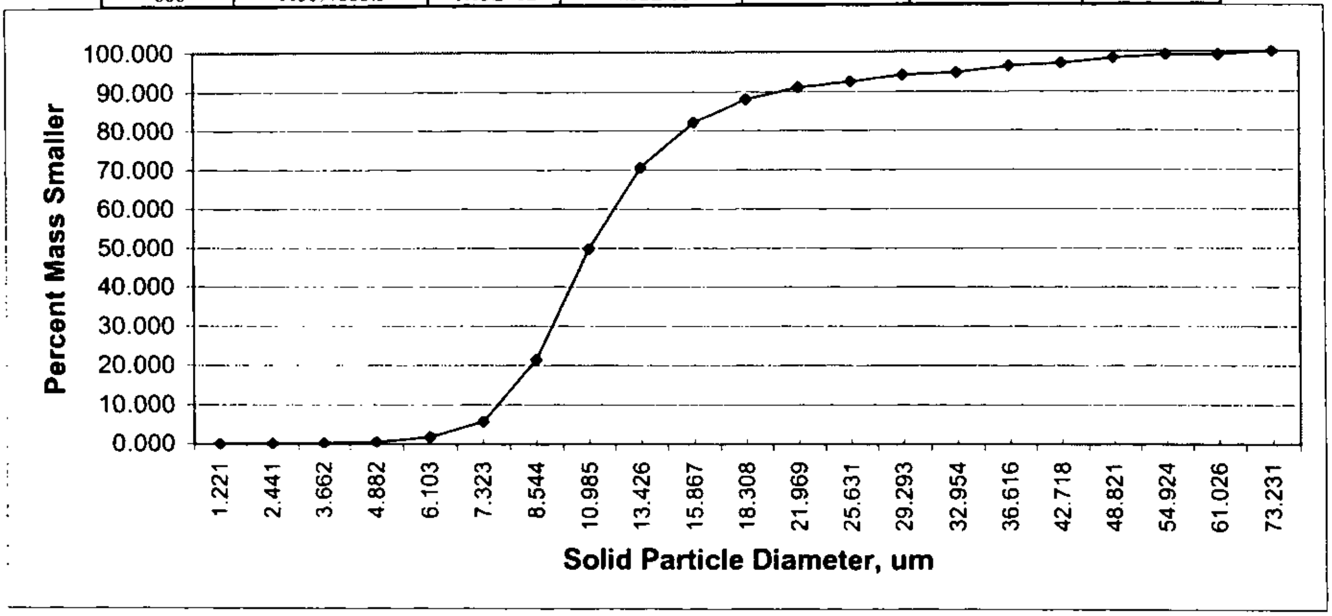


TABLE CT-5
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 5000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller		
10	523.6	5.24E-04	2.62E-06	1.19	1.315	0.000		
20	4188.8	4.19E-03	2.09E-05	9.52	2.630	0.196		
30	14137.2	1.41E-02	7.07E-05	32.13	3.944	0.226		
40	33510.3	3.35E-02	1.68E-04	76.16	5.259	0.514		
50	65449.8	6.54E-02	3.27E-04	148.75	6.574	1.816		
60	113097.3	1.13E-01	5.65E-04	257.04	7.889	5.702		
70	179594.4	1.80E-01	8.98E-04	408.17	9.203	21.348		
90	381703.5	3.82E-01	1.91E-03	867.51	11.833	49.812	60.161	60.161
110	696910.0	6.97E-01	3.48E-03	1583.89	14.462	70.509		
130	1150346.5	1.15E+00	5.75E-03	2614.42	17.092	82.023		
150	1767145.9	1.77E+00	8.84E-03	4016.24	19.722	88.012		
180	3053628.1	3.05E+00	1.53E-02	6940.06	23.666	91.032		
210	4849048.3	4.85E+00	2.42E-02	11020.56	27.610	92.468	91.511	31.350
240	7238229.5	7.24E+00	3.62E-02	16450.52	31.554	94.091		
270	10305994.7	1.03E+01	5.15E-02	23422.72	35.499	94.689		
300	14137166.9	1.41E+01	7.07E-02	32129.92	39.443	96.288	96.288	4.777
350	22449297.5	2.24E+01	1.12E-01	51021.13	46.017	97.011		
400	33510321.6	3.35E+01	1.68E-01	76159.82	52.591	98.340	98.340	2.052
450	47712938.4	4.77E+01	2.39E-01	108438.50	59.165	99.071		
500	65449846.9	6.54E+01	3.27E-01	148749.65	65.738	99.071	99.071	0.731
600	113097335.5	1.13E+02	5.65E-01	257039.40	78.886	100.000	100.000	0.929

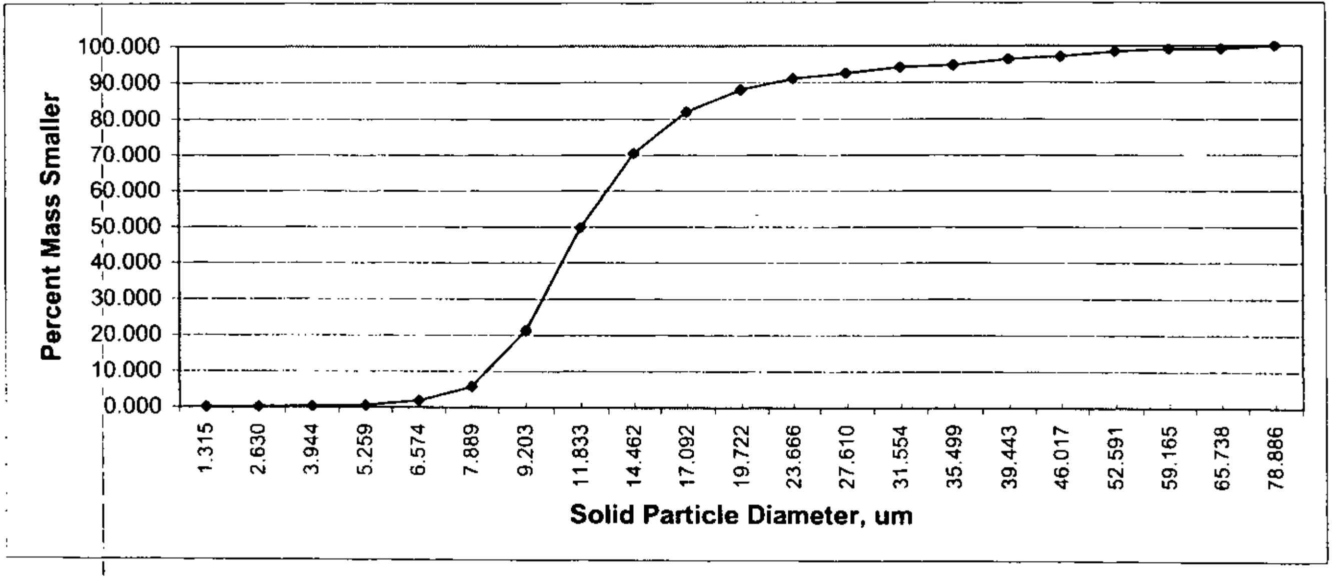


TABLE CT-6
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 6000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.14E-06	1.43	1.397	0.000
20	4188.8	4.19E-03	2.51E-05	11.42	2.794	0.196
30	14137.2	1.41E-02	8.48E-05	38.56	4.191	0.226
40	33510.3	3.35E-02	2.01E-04	91.39	5.589	0.514
50	65449.8	6.54E-02	3.93E-04	178.50	6.986	1.816
60	113097.3	1.13E-01	6.79E-04	308.45	8.383	5.702
70	179594.4	1.80E-01	1.08E-03	489.80	9.780	21.348
90	381703.5	3.82E-01	2.29E-03	1041.01	12.574	49.812
110	696910.0	6.97E-01	4.18E-03	1900.66	15.369	70.509
130	1150346.5	1.15E+00	6.90E-03	3137.31	18.163	82.023
150	1767145.9	1.77E+00	1.06E-02	4819.49	20.957	88.012
180	3053628.1	3.05E+00	1.83E-02	8328.08	25.149	91.032
210	4849048.3	4.85E+00	2.91E-02	13224.68	29.340	92.468
240	7238229.5	7.24E+00	4.34E-02	19740.63	33.532	94.091
270	10305994.7	1.03E+01	6.18E-02	28107.26	37.723	94.689
300	14137166.9	1.41E+01	8.48E-02	38555.91	41.914	96.288
350	22449297.5	2.24E+01	1.35E-01	61225.36	48.900	97.011
400	33510321.6	3.35E+01	2.01E-01	91391.79	55.886	98.340
450	47712938.4	4.77E+01	2.86E-01	130126.20	62.872	99.071
500	65449846.9	6.54E+01	3.93E-01	178499.58	69.857	99.071
600	113097335.5	1.13E+02	6.79E-01	308447.28	83.829	100.000

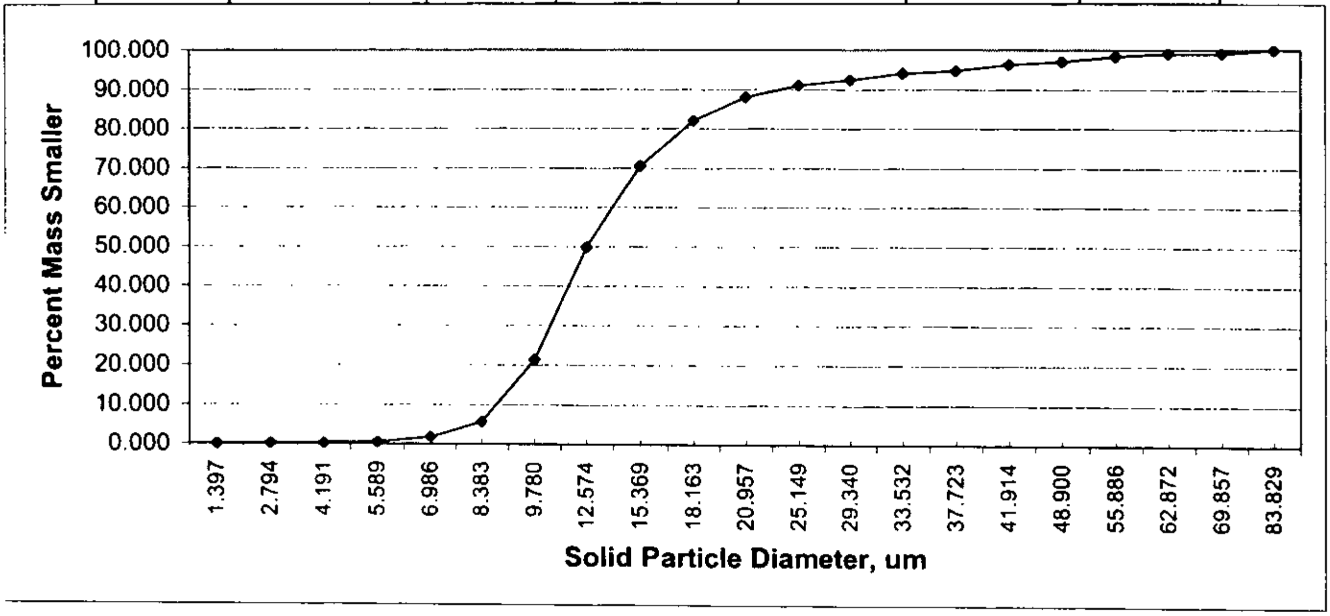


TABLE CT-7
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 7000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	3.67E-06	1.67	1.471	0.000
20	4188.8	4.19E-03	2.93E-05	13.33	2.942	0.196
30	14137.2	1.41E-02	9.90E-05	44.98	4.412	0.226
40	33510.3	3.35E-02	2.35E-04	106.62	5.883	0.514
50	65449.8	6.54E-02	4.58E-04	208.25	7.354	1.816
60	113097.3	1.13E-01	7.92E-04	359.86	8.825	5.702
70	179594.4	1.80E-01	1.26E-03	571.44	10.296	21.348
90	381703.5	3.82E-01	2.67E-03	1214.51	13.237	49.812
110	696910.0	6.97E-01	4.88E-03	2217.44	16.179	70.509
130	1150346.5	1.15E+00	8.05E-03	3660.19	19.121	82.023
150	1767145.9	1.77E+00	1.24E-02	5622.74	22.062	88.012
180	3053628.1	3.05E+00	2.14E-02	9716.09	26.475	91.032
210	4849048.3	4.85E+00	3.39E-02	15428.79	30.887	92.468
240	7238229.5	7.24E+00	5.07E-02	23030.73	35.300	94.091
270	10305994.7	1.03E+01	7.21E-02	32791.80	39.712	94.689
300	14137166.9	1.41E+01	9.90E-02	44981.89	44.124	96.288
350	22449297.5	2.24E+01	1.57E-01	71429.58	51.479	97.011
400	33510321.6	3.35E+01	2.35E-01	106623.75	58.833	98.340
450	47712938.4	4.77E+01	3.34E-01	151813.89	66.187	99.071
500	65449846.9	6.54E+01	4.58E-01	208249.51	73.541	99.071
600	113097335.5	1.13E+02	7.92E-01	359855.16	88.249	100.000

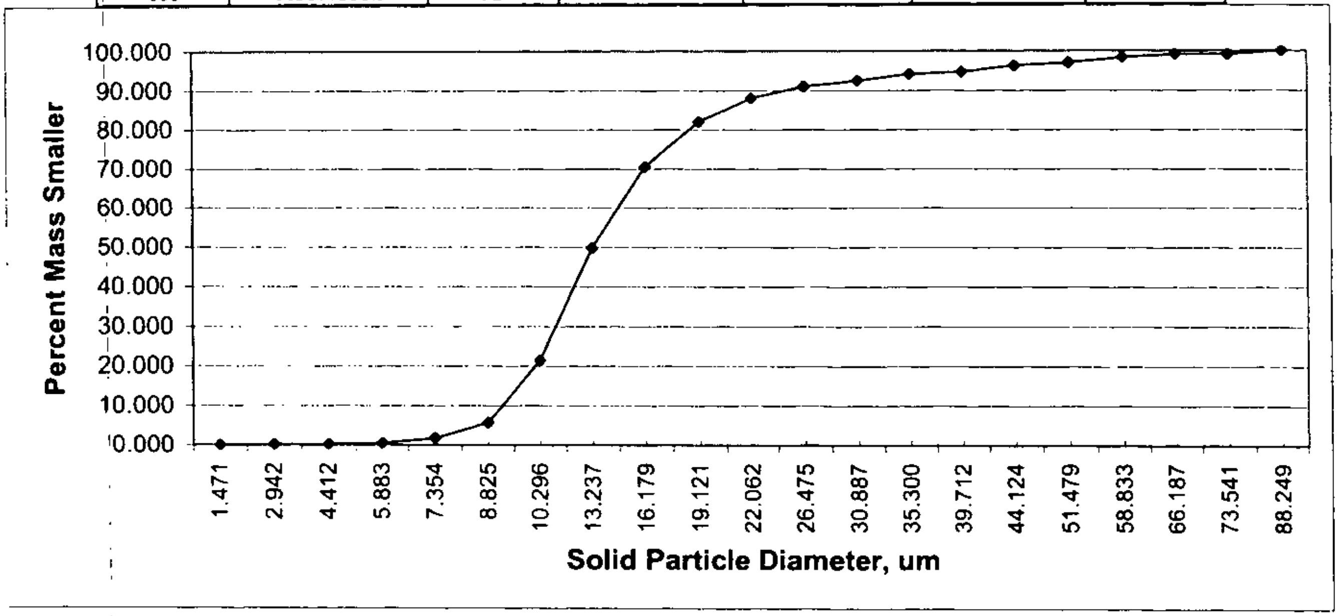


TABLE CT-8
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 7700 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4188.8	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137.2	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510.3	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65449.8	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097.3	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594.4	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381703.5	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910.0	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150346.5	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767145.9	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628.1	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048.3	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229.5	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305994.7	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137166.9	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449297.5	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510321.6	3.35E+01	2.58E-01	117286.13	60.732	98.340
450	47712938.4	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449846.9	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097335.5	1.13E+02	8.71E-01	395840.67	91.098	100.000

TABLE CT-9
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 8000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.19E-06	1.90	1.538	0.000
20	4188.8	4.19E-03	3.35E-05	15.23	3.076	0.196
30	14137.2	1.41E-02	1.13E-04	51.41	4.613	0.226
40	33510.3	3.35E-02	2.68E-04	121.86	6.151	0.514
50	65449.8	6.54E-02	5.24E-04	238.00	7.689	1.816
60	113097.3	1.13E-01	9.05E-04	411.26	9.227	5.702
70	179594.4	1.80E-01	1.44E-03	653.07	10.764	21.348
90	381703.5	3.82E-01	3.05E-03	1388.01	13.840	49.812
110	696910.0	6.97E-01	5.58E-03	2534.22	16.915	70.509
130	1150346.5	1.15E+00	9.20E-03	4183.08	19.991	82.023
150	1767145.9	1.77E+00	1.41E-02	6425.98	23.066	88.012
180	3053628.1	3.05E+00	2.44E-02	11104.10	27.680	91.032
210	4849048.3	4.85E+00	3.88E-02	17632.90	32.293	92.468
240	7238229.5	7.24E+00	5.79E-02	26320.83	36.906	94.091
270	10305994.7	1.03E+01	8.24E-02	37476.34	41.520	94.689
300	14137166.9	1.41E+01	1.13E-01	51407.88	46.133	96.288
350	22449297.5	2.24E+01	1.80E-01	81633.81	53.822	97.011
400	33510321.6	3.35E+01	2.68E-01	121855.72	61.510	98.340
450	47712938.4	4.77E+01	3.82E-01	173501.59	69.199	99.071
500	65449846.9	6.54E+01	5.24E-01	237999.44	76.888	99.071
600	113097335.5	1.13E+02	9.05E-01	411263.04	92.266	100.000

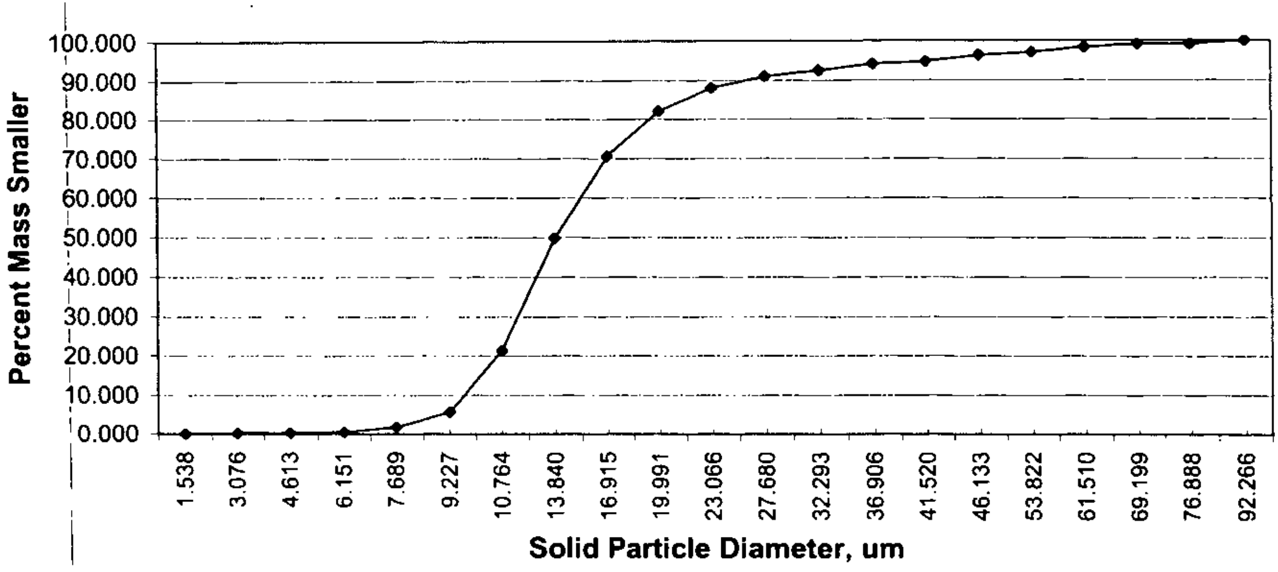


TABLE CT-10
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 9000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.71E-06	2.14	1.599	0.000
20	4188.8	4.19E-03	3.77E-05	17.14	3.199	0.196
30	14137.2	1.41E-02	1.27E-04	57.83	4.798	0.226
40	33510.3	3.35E-02	3.02E-04	137.09	6.397	0.514
50	65449.8	6.54E-02	5.89E-04	267.75	7.997	1.816
60	113097.3	1.13E-01	1.02E-03	462.67	9.596	5.702
70	179594.4	1.80E-01	1.62E-03	734.70	11.195	21.348
90	381703.5	3.82E-01	3.44E-03	1561.51	14.394	49.812
110	696910.0	6.97E-01	6.27E-03	2851.00	17.593	70.509
130	1150346.5	1.15E+00	1.04E-02	4705.96	20.791	82.023
150	1767145.9	1.77E+00	1.59E-02	7229.23	23.990	88.012
180	3053628.1	3.05E+00	2.75E-02	12492.11	28.788	91.032
210	4849048.3	4.85E+00	4.36E-02	19837.02	33.586	92.468
240	7238229.5	7.24E+00	6.51E-02	29610.94	38.384	94.091
270	10305994.7	1.03E+01	9.28E-02	42160.89	43.182	94.689
300	14137166.9	1.41E+01	1.27E-01	57833.86	47.980	96.288
350	22449297.5	2.24E+01	2.02E-01	91838.04	55.977	97.011
400	33510321.6	3.35E+01	3.02E-01	137087.68	63.973	98.340
450	47712938.4	4.77E+01	4.29E-01	195189.29	71.970	99.071
500	65449846.9	6.54E+01	5.89E-01	267749.37	79.967	99.071
600	113097335.5	1.13E+02	1.02E+00	462670.92	95.960	100.000

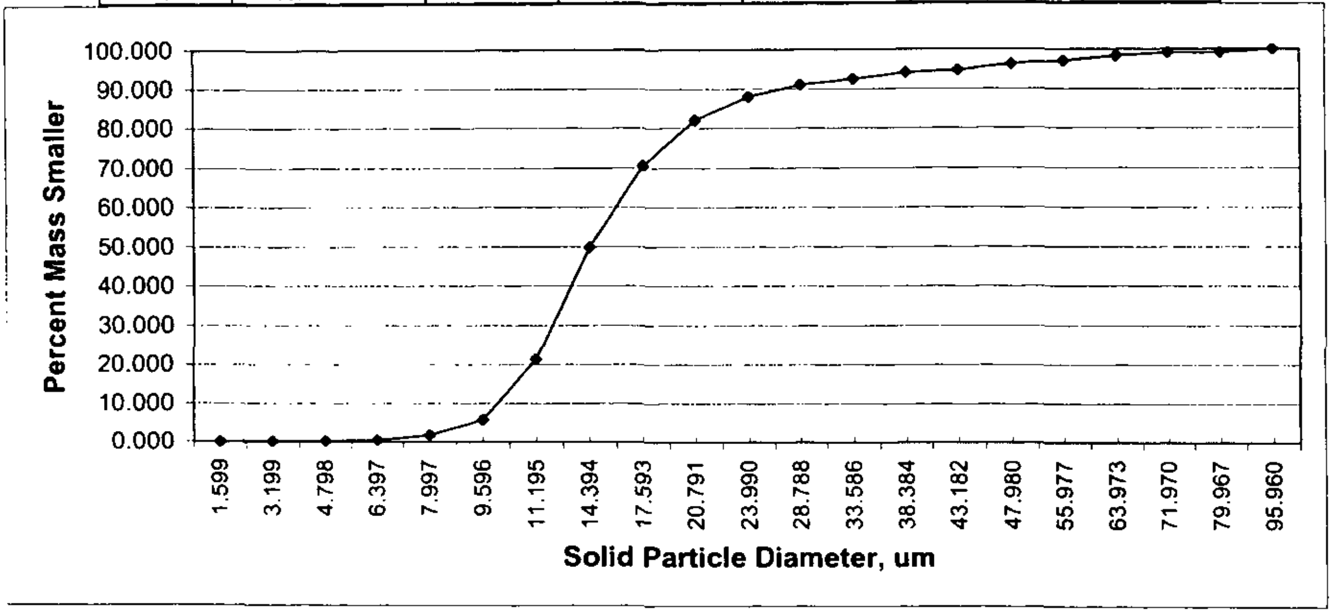


TABLE CT-11
RESULTANT SOLID PARTICULAT SIZE DISTRIBUTION (TDS = 10000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.24E-06	2.38	1.657	0.000
20	4188.8	4.19E-03	4.19E-05	19.04	3.313	0.196
30	14137.2	1.41E-02	1.41E-04	64.26	4.970	0.226
40	33510.3	3.35E-02	3.35E-04	152.32	6.626	0.514
50	65449.8	6.54E-02	6.54E-04	297.50	8.283	1.816
60	113097.3	1.13E-01	1.13E-03	514.08	9.939	5.702
70	179594.4	1.80E-01	1.80E-03	816.34	11.596	21.348
90	381703.5	3.82E-01	3.82E-03	1735.02	14.909	49.812
110	696910.0	6.97E-01	6.97E-03	3167.77	18.222	70.509
130	1150346.5	1.15E+00	1.15E-02	5228.85	21.535	82.023
150	1767145.9	1.77E+00	1.77E-02	8032.48	24.848	88.012
180	3053628.1	3.05E+00	3.05E-02	13880.13	29.817	91.032
210	4849048.3	4.85E+00	4.85E-02	22041.13	34.787	92.468
240	7238229.5	7.24E+00	7.24E-02	32901.04	39.756	94.091
270	10305994.7	1.03E+01	1.03E-01	46845.43	44.726	94.689
300	14137166.9	1.41E+01	1.41E-01	64259.85	49.695	96.288
350	22449297.5	2.24E+01	2.24E-01	102042.26	57.978	97.011
400	33510321.6	3.35E+01	3.35E-01	152319.64	66.260	98.340
450	47712938.4	4.77E+01	4.77E-01	216876.99	74.543	99.071
500	65449846.9	6.54E+01	6.54E-01	297499.30	82.825	99.071
600	113097335.5	1.13E+02	1.13E+00	514078.80	99.390	100.000

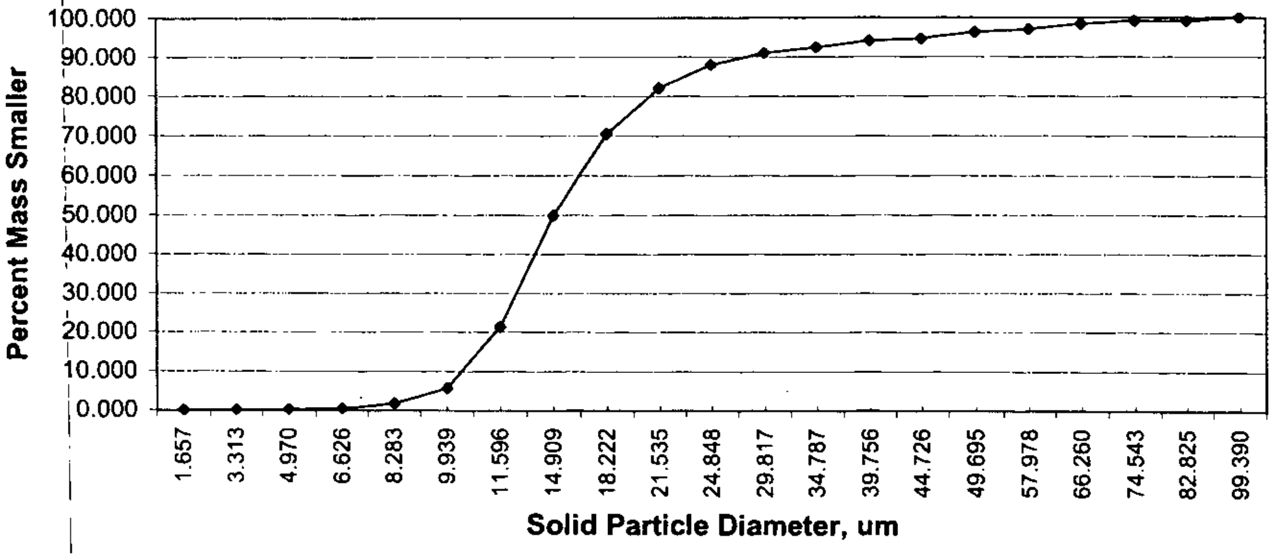


TABLE CT-12
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 11000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4188.8	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137.2	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510.3	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65449.8	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097.3	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594.4	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381703.5	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910.0	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150346.5	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767145.9	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628.1	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048.3	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229.5	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305994.7	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137166.9	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449297.5	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510321.6	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938.4	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449846.9	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097335.5	1.13E+02	1.24E+00	565486.68	102.599	100.000

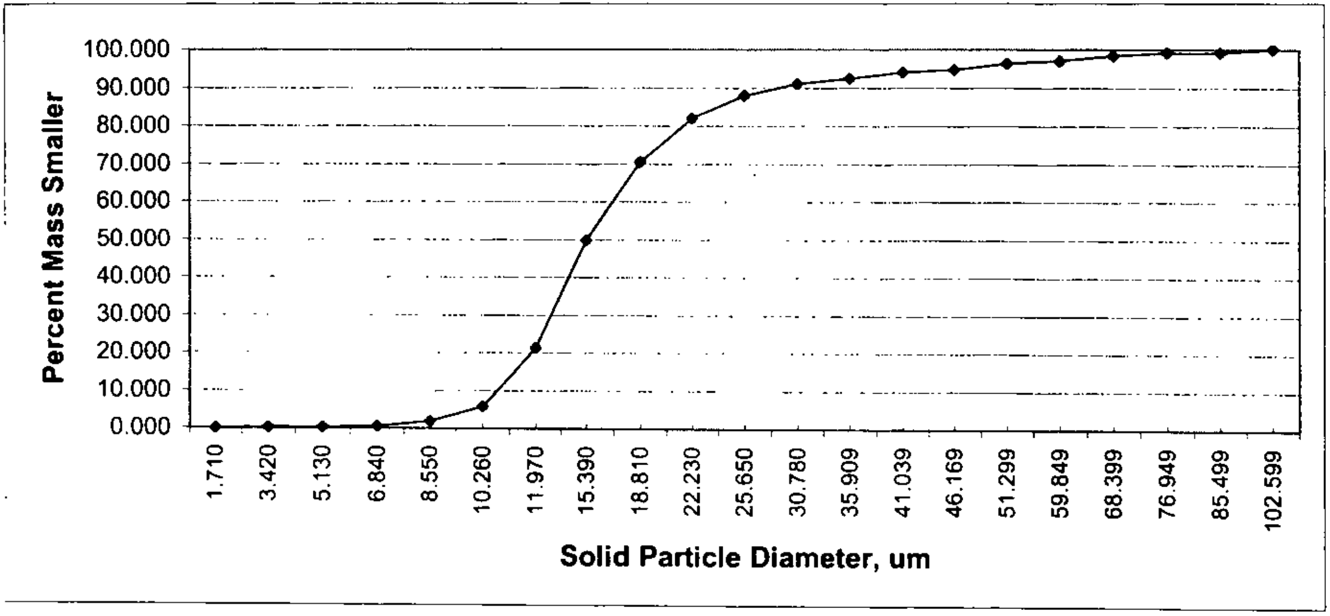


TABLE CT-13
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 12000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	6.28E-06	2.86	1.760	0.000
20	4188.8	4.19E-03	5.03E-05	22.85	3.521	0.196
30	14137.2	1.41E-02	1.70E-04	77.11	5.281	0.226
40	33510.3	3.35E-02	4.02E-04	182.78	7.041	0.514
50	65449.8	6.54E-02	7.85E-04	357.00	8.801	1.816
60	113097.3	1.13E-01	1.36E-03	616.89	10.562	5.702
70	179594.4	1.80E-01	2.16E-03	979.61	12.322	21.348
90	381703.5	3.82E-01	4.58E-03	2082.02	15.843	49.812
110	696910.0	6.97E-01	8.36E-03	3801.33	19.363	70.509
130	1150346.5	1.15E+00	1.38E-02	6274.62	22.884	82.023
150	1767145.9	1.77E+00	2.12E-02	9638.98	26.404	88.012
180	3053628.1	3.05E+00	3.66E-02	16656.15	31.685	91.032
210	4849048.3	4.85E+00	5.82E-02	26449.35	36.966	92.468
240	7238229.5	7.24E+00	8.69E-02	39481.25	42.247	94.091
270	10305994.7	1.03E+01	1.24E-01	56214.52	47.528	94.689
300	14137166.9	1.41E+01	1.70E-01	77111.82	52.809	96.288
350	22449297.5	2.24E+01	2.69E-01	122450.71	61.610	97.011
400	33510321.6	3.35E+01	4.02E-01	182783.57	70.412	98.340
450	47712938.4	4.77E+01	5.73E-01	260252.39	79.213	99.071
500	65449846.9	6.54E+01	7.85E-01	356999.17	88.015	99.071
600	113097335.5	1.13E+02	1.36E+00	616894.56	105.618	100.000

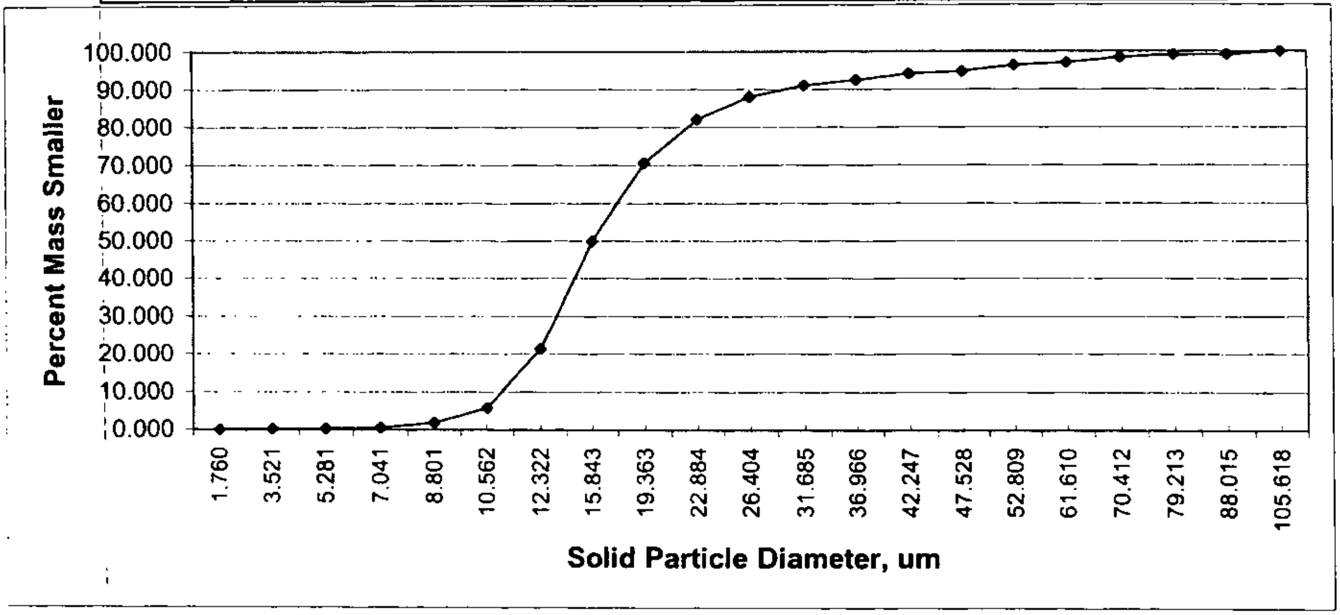


TABLE CT-14
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 30000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	1.57E-05	7.14	2.389	0.000
20	4188.8	4.19E-03	1.26E-04	57.12	4.778	0.196
30	14137.2	1.41E-02	4.24E-04	192.78	7.167	0.226
40	33510.3	3.35E-02	1.01E-03	456.96	9.556	0.514
50	65449.8	6.54E-02	1.96E-03	892.50	11.945	1.816
60	113097.3	1.13E-01	3.39E-03	1542.24	14.335	5.702
70	179594.4	1.80E-01	5.39E-03	2449.01	16.724	21.348
90	381703.5	3.82E-01	1.15E-02	5205.05	21.502	49.812
110	696910.0	6.97E-01	2.09E-02	9503.32	26.280	70.509
130	1150346.5	1.15E+00	3.45E-02	15686.54	31.058	82.023
150	1767145.9	1.77E+00	5.30E-02	24097.44	35.836	88.012
180	3053628.1	3.05E+00	9.16E-02	41640.38	43.004	91.032
210	4849048.3	4.85E+00	1.45E-01	66123.39	50.171	92.468
240	7238229.5	7.24E+00	2.17E-01	98703.13	57.338	94.091
270	10305994.7	1.03E+01	3.09E-01	140536.29	64.505	94.689
300	14137166.9	1.41E+01	4.24E-01	192779.55	71.673	96.288
350	22449297.5	2.24E+01	6.73E-01	306126.78	83.618	97.011
400	33510321.6	3.35E+01	1.01E+00	456958.93	95.564	98.340
450	47712938.4	4.77E+01	1.43E+00	650630.98	107.509	99.071
500	65449846.9	6.54E+01	1.96E+00	892497.91	119.455	99.071
600	113097335.5	1.13E+02	3.39E+00	1542236.39	143.346	100.000

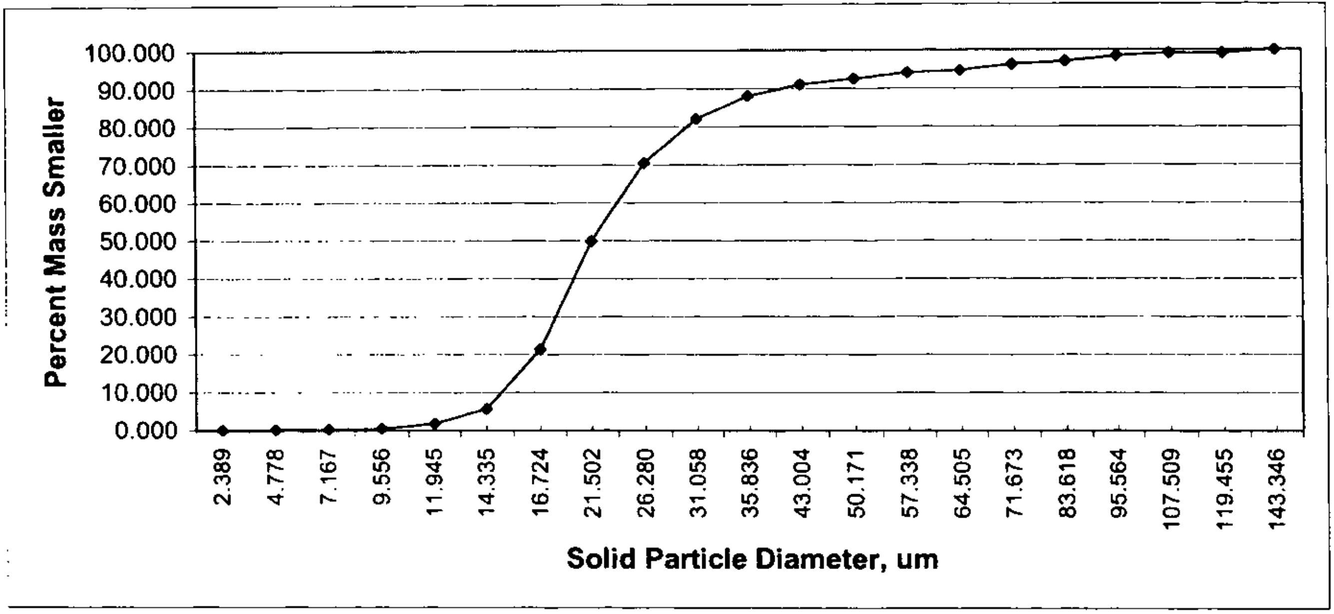
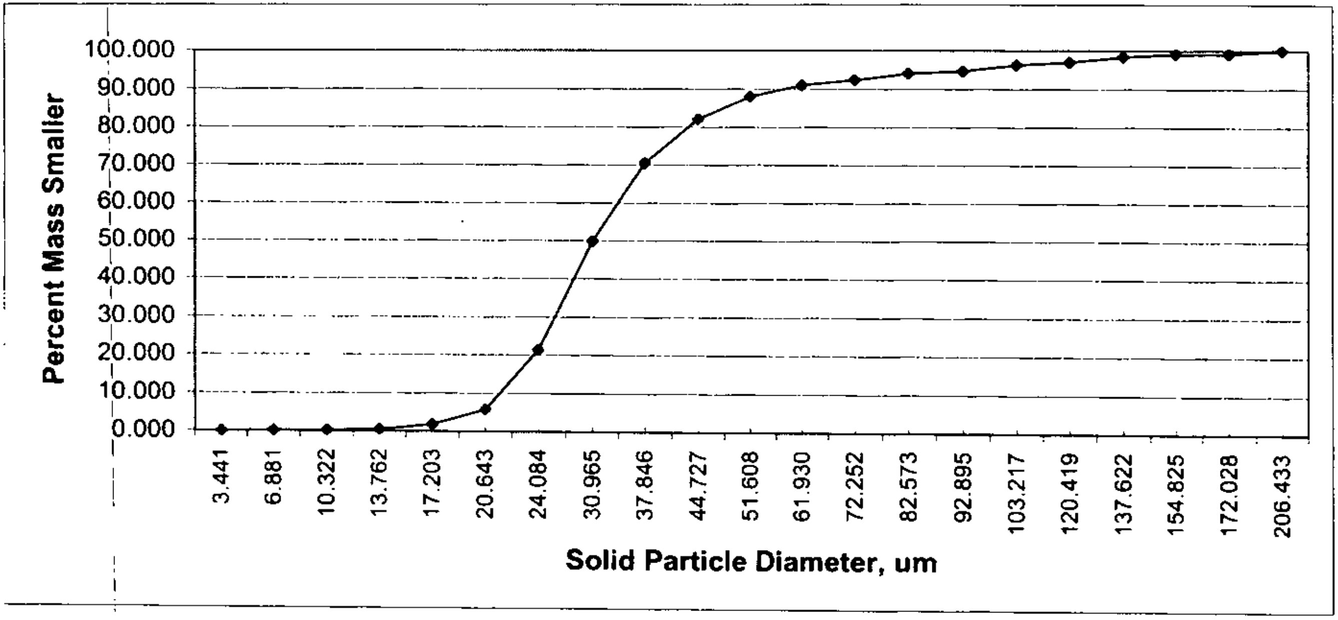


TABLE CT-15
RESULTANT SOLID PARTICULATE SIZE DISTRIBUTION (TDS = 30000 ppmw)

EPRI Droplet Diameter (um)	Droplet Volume (um3)	Droplet Mass (ug)	Particulate Mass (Solids) (ug)	Solid Particulate Volume (um3)	Solid Particulate Diameter (um)	EPRI % Mass Smaller
10	523.6	5.24E-04	4.69E-05	21.32	3.441	0.000
20	4188.8	4.19E-03	3.75E-04	170.60	6.881	0.196
30	14137.2	1.41E-02	1.27E-03	575.77	10.322	0.226
40	33510.3	3.35E-02	3.00E-03	1364.78	13.762	0.514
50	65449.8	6.54E-02	5.86E-03	2665.59	17.203	1.816
60	113097.3	1.13E-01	1.01E-02	4606.15	20.643	5.702
70	179594.4	1.80E-01	1.61E-02	7314.39	24.084	21.348
90	381703.5	3.82E-01	3.42E-02	15545.74	30.965	49.812
110	696910.0	6.97E-01	6.24E-02	28383.24	37.846	70.509
130	1150346.5	1.15E+00	1.03E-01	46850.48	44.727	82.023
150	1767145.9	1.77E+00	1.58E-01	71971.03	51.608	88.012
180	3053628.1	3.05E+00	2.74E-01	124365.94	61.930	91.032
210	4849048.3	4.85E+00	4.34E-01	197488.51	72.252	92.468
240	7238229.5	7.24E+00	6.49E-01	294793.35	82.573	94.091
270	10305994.7	1.03E+01	9.23E-01	419735.06	92.895	94.689
300	14137166.9	1.41E+01	1.27E+00	575768.25	103.217	96.288
350	22449297.5	2.24E+01	2.01E+00	914298.66	120.419	97.011
400	33510321.6	3.35E+01	3.00E+00	1364784.01	137.622	98.340
450	47712938.4	4.77E+01	4.28E+00	1943217.86	154.825	99.071
500	65449846.9	6.54E+01	5.86E+00	2665593.77	172.028	99.071
600	113097335.5	1.13E+02	1.01E+01	4606146.03	206.433	100.000



Calculating Realistic PM_{10} Emissions from Cooling Towers

Abstract No. 216 **Session No. AM-1b**

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ABSTRACT

Particulate matter less than 10 micrometers in diameter (PM_{10}) emissions from wet cooling towers may be calculated using the methodology presented in EPA's AP-42[1], which assumes that all total dissolved solids (TDS) emitted in "drift" particles (liquid water entrained in the air stream and carried out of the tower through the induced draft fan stack.) are PM_{10}. However, for wet cooling towers with medium to high TDS levels, this method is overly conservative, and predicts significantly higher PM_{10} emissions than would actually occur, even for towers equipped with very high efficiency drift eliminators (e.g., 0.0006% drift rate). Such over-prediction may result in unrealistically high PM_{10} modeled concentrations and/or the need to purchase expensive Emission Reduction Credits (ERCs) in PM_{10} non-attainment areas. Since these towers have fairly low emission points (10 to 15 m above ground), over-predicting PM_{10} emission rates can easily result in exceeding federal Prevention of Significant Deterioration (PSD) significance levels at a project's fenceline. This paper presents a method for computing realistic PM_{10} emissions from cooling towers with medium to high TDS levels.

INTRODUCTION

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Wet, or evaporative, cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers, for example, steam condensers. Wet cooling towers provide direct contact between the cooling water and air passing through the tower, and as part of normal operation, a very small amount of the circulating water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Because the drift droplets contain the same chemical impurities as the water circulating through the tower, the particulate matter constituent of the drift droplets may be classified as an emission. The magnitude of the drift loss is influenced by the number and size of droplets produced within the tower, which are determined by the tower fill design, tower design, the air and water patterns, and design of the drift eliminators.

AP-42 METHOD OF CALCULATING DRIFT PARTICULATE

EPA's AP-42[1] provides available particulate emission factors for wet cooling towers, however, these values only have an emission factor rating of "E" (the lowest level of confidence acceptable). They are also rather high, compared to typical present-day manufacturers' guaranteed drift rates, which are on the order of 0.0006%. (Drift emissions are typically expressed as a percentage of the cooling tower water circulation rate). AP-42 states that "a *conservatively high* PM_{10} emission factor can be obtained by (a) multiplying the total liquid drift factor by the TDS fraction in the circulating water, and (b) assuming that once the water evaporates, all remaining solid particles are within the PM_{10} range." (Italics per EPA).

If TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS for the make-up water and multiplying it by the cooling tower cycles of concentration. [The cycles of concentration is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water.]

Using AP-42 guidance, the total particulate emissions (PM) (after the pure water has evaporated) can be expressed as:

$$\text{PM} = \text{Water Circulation Rate} \times \text{Drift Rate} \times \text{TDS} \qquad [1]$$

For example, for a typical power plant wet cooling tower with a water circulation rate of 146,000 gallons per minute (gpm), drift rate of 0.0006%, and TDS of 7,700 parts per million by weight (ppmw):

$$\text{PM} = 146{,}000 \text{ gpm} \times 8.34 \text{ lb water/gal} \times 0.0006/100 \times 7{,}700 \text{ lb solids}/10^6 \text{ lb water} \times 60 \text{ min/hr} = \underline{3.38 \text{ lb/hr}}$$

On an annual basis, this is equivalent to almost 15 tons per year (tpy). Even for a state-of-the-art drift eliminator system, this is not a small number, especially if assumed to all be equal to PM_{10}, a regulated criteria pollutant. However, as the following analysis demonstrates, only a very small fraction is actually PM_{10}.

COMPUTING THE PM_{10} FRACTION

Based on a representative drift droplet size distribution and TDS in the water, the amount of solid mass in each drop size can be calculated. That is, for a given initial droplet size, assuming that the mass of dissolved solids condenses to a spherical particle after all the water evaporates, and assuming the density of the TDS is equivalent to a representative salt (e.g., sodium chloride), the diameter of the final solid particle can be calculated. Thus, using the drift droplet size distribution, the percentage of drift mass containing particles small enough to produce PM_{10} can be calculated. This method is conservative as the final particle is assumed to be perfectly spherical; hence as small a particle as can exist.

The droplet size distribution of the drift emitted from the tower is critical to performing the analysis. Brentwood Industries, a drift eliminator manufacturer, was contacted and agreed to provide drift eliminator test data from a test conducted by Environmental Systems Corporation (ESC) at the Electric Power Research Institute (EPRI) test facility in Houston, Texas in 1988 (Aull[2], 1999). The data consist of water droplet size distributions for a drift eliminator that achieved a tested drift rate of 0.0003 percent. As we are using a 0.0006 percent drift rate, it is reasonable to expect that the 0.0003 percent drift rate would produce smaller droplets, therefore, this size distribution data can be assumed to be conservative for predicting the fraction of PM_{10} in the total cooling tower PM emissions.

In calculating PM_{10} emissions the following assumptions were made:

- Each water droplet was assumed to evaporate shortly after being emitted into ambient air, into a single, solid, spherical particle.
- Drift water droplets have a density (ρ_w) of water; $1.0\ \text{g/cm}^3$ or $1.0 * 10^{-6}\ \mu g/\mu m^3$.
- The solid particles were assumed to have the same density (ρ_{TDS}) as sodium chloride, (i.e., 2.2 g/cm^3).

Using the formula for the volume of a sphere, $V = 4\pi r^3/3$, and the density of pure water, $\rho_w = 1.0\ \text{g/cm}^3$, the following equations can be used to derive the solid particulate diameter, D_p, as a function of the TDS, the density of the solids, and the initial drift droplet diameter, D_d:

$$\text{Volume of drift droplet} = (4/3)\pi(D_d/2)^3 \qquad [2]$$

$$\text{Mass of solids in drift droplet} = (\text{TDS})(\rho_w)(\text{Volume of drift droplet}) \qquad [3]$$

substituting,

$$\text{Mass of solids in drift} = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [4]$$

Assuming the solids remain and coalesce after the water evaporates, the mass of solids can also be expressed as:

$$\text{Mass of solids} = (\rho_{TDS})\ (\text{solid particle volume}) = (\rho_{TDS})(4/3)\pi(D_p/2)^3 \qquad [5]$$

Equations [4] and [5] are equivalent:

$$(\rho_{TDS})(4/3)\pi(D_p/2)^3 = (\text{TDS})(\rho_w)(4/3)\pi(D_d/2)^3 \qquad [6]$$

Solving for D_p:

$$D_p = D_d\,[(\text{TDS})(\rho_w/\rho_{TDS})]^{1/3} \qquad [7]$$

Where,

TDS is in units of ppmw

D_p = diameter of solid particle, micrometers (μm)

D_d = diameter of drift droplet, μm

Using formulas [2] – [7] and the particle size distribution test data, Table 1 can be constructed for drift from a wet cooling tower having the same characteristics as our example; 7,700 ppmw TDS and a 0.0006% drift rate. The first and last columns of this table are the particle size distribution derived from test results provided by Brentwood Industries. Using straight-line interpolation for a solid particle size 10 μm in diameter, we conclude that approximately 14.9 percent of the mass emissions are equal to or smaller than PM_{10}. The balance of the solid particulate are particulate greater than 10 μm. Hence, PM_{10} emissions from this tower would be equal to PM emissions x 0.149, or 3.38 lb/hr x 0.149 = 0.50 lb/hr. The process is repeated in Table 2, with all parameters equal except that the TDS is 11,000 ppmw. The result is that approximately 5.11 percent are smaller at 11,000 ppm. Thus, while total PM emissions are larger by virtue of a higher TDS, overall PM_{10} emissions are actually lower, because more of the solid particles are larger than 10 μm.

Table 1. Resultant Solid Particulate Size Distribution (TDS = 7700 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2][1]	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	4.03E-06	1.83	1.518	0.000
20	4189	4.19E-03	3.23E-05	14.66	3.037	0.196
30	14137	1.41E-02	1.09E-04	49.48	4.555	0.226
40	33510	3.35E-02	2.58E-04	117.29	6.073	0.514
50	65450	6.54E-02	5.04E-04	229.07	7.591	1.816
60	113097	1.13E-01	8.71E-04	395.84	9.110	5.702
70	179594	1.80E-01	1.38E-03	628.58	10.628	21.348
90	381704	3.82E-01	2.94E-03	1335.96	13.665	49.812
110	696910	6.97E-01	5.37E-03	2439.18	16.701	70.509
130	1150347	1.15E+00	8.86E-03	4026.21	19.738	82.023
150	1767146	1.77E+00	1.36E-02	6185.01	22.774	88.012
180	3053628	3.05E+00	2.35E-02	10687.70	27.329	91.032
210	4849048	4.85E+00	3.73E-02	16971.67	31.884	92.468
240	7238229	7.24E+00	5.57E-02	25333.80	36.439	94.091
270	10305995	1.03E+01	7.94E-02	36070.98	40.994	94.689
300	14137167	1.41E+01	1.09E-01	49480.08	45.549	96.288
350	22449298	2.24E+01	1.73E-01	78572.54	53.140	97.011
400	33510322	3.35E+01	2.58E-01	117288.13	60.732	98.340
450	47712938	4.77E+01	3.67E-01	166995.28	68.323	99.071
500	65449847	6.54E+01	5.04E-01	229074.46	75.915	99.071
600	113097336	1.13E+02	8.71E-01	395840.67	91.098	100.000

[1] Bracketed numbers refer to equation number in text.

The percentage of PM_{10}/PM was calculated for cooling tower TDS values from 1000 to 12000 ppmw and the results are plotted in Figure 1. Using these data, Figure 2 presents predicted PM_{10} emission rates for the 146,000 gpm example tower. As shown in this figure, the PM emission rate increases in a straight line as TDS increases, however, the PM_{10} emission rate increases to a maximum at around a TDS of 4000 ppmw, and then begins to decline. The reason is that at higher TDS, the drift droplets contain more solids and therefore, upon evaporation, result in larger solid particles for any given initial droplet size.

CONCLUSION

The emission factors and methodology given in EPA's AP-42[1] Chapter 13.4 *Wet Cooling Towers*, do not account for the droplet size distribution of the drift exiting the tower. This is a critical factor, as more than 85% of the mass of particulate in the drift from most cooling towers will result in solid particles larger than PM_{10} once the water has evaporated. Particles larger than PM_{10} are no longer a regulated air pollutant, because their impact on human health has been shown to be insignificant. Using reasonable, conservative assumptions and a realistic drift droplet size distribution, a method is now available for calculating realistic PM_{10} emission rates from wet mechanical draft cooling towers equipped with modern, high-efficiency drift eliminators and operating at medium to high levels of TDS in the circulating water.

Table 2. Resultant Solid Particulate Size Distribution (TDS = 11000 ppmw)

EPRI Droplet Diameter (μm)	Droplet Volume (μm^3) [2]'	Droplet Mass (μg) [3]	Particle Mass (Solids) (μg) [4]	Solid Particle Volume (μm^3)	Solid Particle Diameter (μm) [7]	EPRI % Mass Smaller
10	524	5.24E-04	5.76E-06	2.62	1.710	0.000
20	4189	4.19E-03	4.61E-05	20.94	3.420	0.196
30	14137	1.41E-02	1.56E-04	70.69	5.130	0.226
40	33510	3.35E-02	3.69E-04	167.55	6.840	0.514
50	65450	6.54E-02	7.20E-04	327.25	8.550	1.816
60	113097	1.13E-01	1.24E-03	565.49	10.260	5.702
70	179594	1.80E-01	1.98E-03	897.97	11.970	21.348
90	381704	3.82E-01	4.20E-03	1908.52	15.390	49.812
110	696910	6.97E-01	7.67E-03	3484.55	18.810	70.509
130	1150347	1.15E+00	1.27E-02	5751.73	22.230	82.023
150	1767146	1.77E+00	1.94E-02	8835.73	25.650	88.012
180	3053628	3.05E+00	3.36E-02	15268.14	30.780	91.032
210	4849048	4.85E+00	5.33E-02	24245.24	35.909	92.468
240	7238229	7.24E+00	7.96E-02	36191.15	41.039	94.091
270	10305995	1.03E+01	1.13E-01	51529.97	46.169	94.689
300	14137167	1.41E+01	1.56E-01	70685.83	51.299	96.288
350	22449298	2.24E+01	2.47E-01	112246.49	59.849	97.011
400	33510322	3.35E+01	3.69E-01	167551.61	68.399	98.340
450	47712938	4.77E+01	5.25E-01	238564.69	76.949	99.071
500	65449847	6.54E+01	7.20E-01	327249.23	85.499	99.071
600	113097336	1.13E+02	1.24E+00	565486.68	102.599	100.000

Figure 1: Percentage of Drift PM that Evaporates to PM10

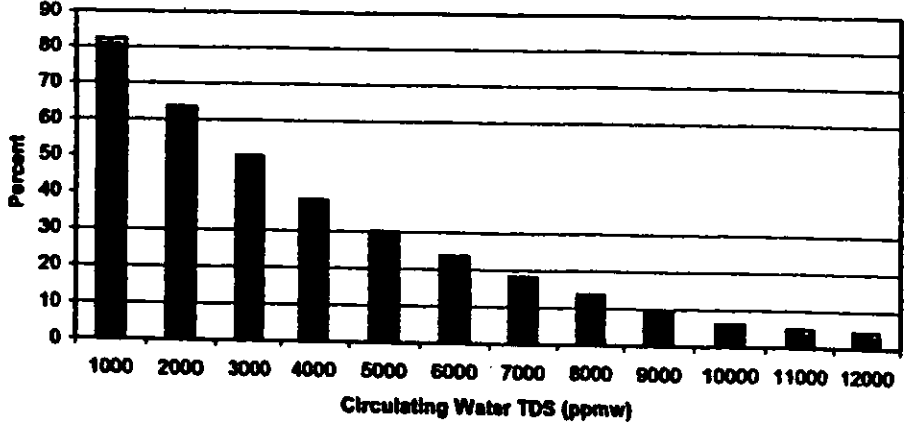
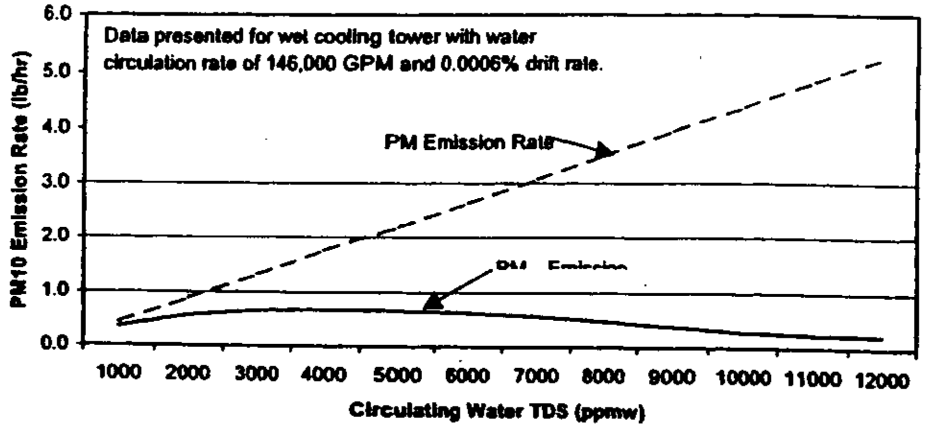


Figure 2: PM_{10} Emission Rate vs. TDS



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1. EPA, 1995. Compilation of Air pollutant Emission Factors, AP-42 Fifth edition, Volume I: *Stationary Point and Area Sources*, Chapter 13.4 Wet Cooling Towers, http://www.epa.gov/ttn/chief/ap42/, United States Environmental Protection Agency, Office of Air Quality Planning and Standards, January.

2. Aull, 1999. Memorandum from R. Aull, Brentwood Industries to J. Reisman, Greystone, December 7, 1999.

KEY WORDS

Drift
Drift eliminators
Cooling tower
PM_{10} emissions
TDS

HAZARDOUS AIR POLLUTANT
EMISSIONS

TABLE HAPS-1
TRACE METAL HAPS EMISSIONS ESTIMATES FOR FPL GLADES POWER PARK

	Antimony	Arsenic	Beryllium	Cadmium	Chromium	Cobalt	Lead	Manganese	Mercury	Nickel	Selenium	Vanadium
Emissions-EPA Factors (EF = a x (C/A x PM)^{b}												
Multiplier - a	0.92	3.1	1.2	3.3	3.7	1.7	3.4	3.8		4.4		3.8
Exponent - b	0.63	0.85	1.1	0.5	0.58	0.69	0.8	0.6		0.48		0.6
Concentration (C) (ppm)	1.21	23.74	2.890	0.09	14.68	7.22	7.990	22.65		90.000	3.67	500.000
Actual PM Concentration (PM) (lb/mmBtu)	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130	0.0130		0.0130		0.0130
Ash Concentration (A) (fraction)	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273	0.1273		0.1273		0.1273
Emission Factor (lb/10^12 Btu)	0.246	6.581	0.313	0.316	4.679	1.378	2.889	6.285	1.206	12.760	14.668	40.238
Heat Input (mmBtu/hr)	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700
Maximum Fuel Input (lb/hr)	695,444	695,444	695,444	695,444	695,444	695,444	695,444	695,444	695,444	725,102	695,444	725,102
Emissions (lb/hr)	0.002	0.057	0.003	0.003	0.041	0.012	0.025	0.055	0.010	0.111	0.128	0.350
Uncontrolled (lb/hr)	0.841	16.510	2.010	0.063	10.209	5.021	5.557	15.752		65.259	2.552	362.551
Removal	99.75%	99.65%	99.86%	95.60%	99.60%	99.76%	99.55%	99.65%		99.83%	95.00%	99.90%
Emissions (tons/yr/plant)	0.019	0.502	0.024	0.024	0.357	0.105	0.220	0.479	0.092	0.972	1.118	3.067

Sources: EPA,1998, AP-42, Table 1.1-16 (all metals except mercury, nickel and vanadium), Trace Metal Concentration based on upper 95% Confidence Interval from
USGS COALQUAL Database Trace Elements for the Central Appalachian Region. Mercury based on average of USGS information. Nickel and vanadium based on coal/petroleum coke blend.
http://energy.er.usgs.gov/coalqual.htm

Controlled Selenium emissions based on 95% control from FGD system.

TABLE HAPS-2
HALOGEN HAP EMISSIONS ESTIMATES FOR FPL GLADES POWER PARK

	HCL	HF
Halogen Emission Calculation		
Concentration (ppm)	1040.5	89.91
Maximum Fuel Input (lb/hr)	695,444	695,444
Uncontrolled Emissions (lb/hr)	724	63
Removal	97%	97%
Emissions (lb/hr/unit)	21.71	2.00
Emissions (lb/hr/plant)	43.42	4.00
Heat Input (MMBtu/hr)	8,700	8,700
Emissions (lb/MMBtu)	0.0025	0.00023
Net Power Output (MW)	980.00	980.00
Emissions (lb/MW-hr)	0.0222	0.0020
Emissions (tons/year/unit)	95.1	8.8
Emissions (tons/yr/plant)	190.2	17.5

Sources: CL and F Concentrations based on upper 95-percent Confidence Interval from USES COEQUAL Database Trace Elements for the Central Appalachian Region http://energy.er.usgs.gov/coalqual.htm.

TABLE HAPS-3

PCDD/PCDF AND RADIONUCLIDES HAP EMISSIONS ESTIMATES FOR FPL GLADES POWER PARK

Organic Compound	Emission Factor	Emisson Factor Units	Emissions per Unit		Emissions per Unit	
			Amount	Units	Amount	Units
Total PCDD/PCDF	1.8E-09	lb/ton	6.8E-07	lb/hr	5.94E-06	tons/year
Radionuclides	52.8	picoCuri/gram PM	3.13E+06	piC/hr	5.48E+10	piC/yr
Data used in Calculation:						
Maximum Fuel Input (lb/hr)	769,912					
Maximum Fuel Input (ton/hr)	384.96					
Heat Input (MMBtu/hr)	8,700					
PM Emissons (lb/MMBtu)	0.015					
PM Emissons (lb/hr)	130.50					
PM Emissons (grams/hr)	59194.80					

Note: ESP = Electrostatic precipitator.
FF = Fabric Filter.
PCDD = Polychlorinated Dibenzo-P-Dioxins and PCDF=Polychlorinated Dibenzofurans.
pico = 10^{-12}.

Source: EPA, 1998, Table 1.1-12 for PCDD and PCDF (with ESP or FF); EPRI, 1994 for Radionuclides.

TABLE HAPS-4
ORGANIC HAP EMISSIONS ESTIMATES FOR FPL GLADES POWER PARK

Organic Compound	Emission Factor (lb/ton)	Emissions per Unit (lb/hr)	Emissions per Plant (TPY)
Acetaldehyde	5.7E-04	2.2E-01	1.92
Acetophenone	1.5E-05	5.8E-03	0.05
Acrolein	2.9E-04	1.1E-01	0.98
Benzene	1.3E-03	5.0E-01	4.38
Benzyl chloride	7.0E-04	2.7E-01	2.36
Biphenyl	1.7E-06	6.5E-04	0.01
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	2.8E-02	0.25
Bromoform	3.9E-05	1.5E-02	0.13
Carbon disulfide	1.3E-04	5.0E-02	0.44
2-Chloroacetophenone	7.0E-06	2.7E-03	0.02
Chlorobenzene	2.2E-05	8.5E-03	0.07
Chloroform	5.9E-05	2.3E-02	0.20
Cumene	5.3E-06	2.0E-03	0.02
Cyanide	2.5E-03	9.6E-01	8.43
2,4-Dintrotoluene	2.8E-07	1.1E-04	0.00
Dimethly sulfate	4.8E-05	1.8E-02	0.16
Ethyl benzene	9.4E-05	3.6E-02	0.32
Ethyl chloride	4.2E-05	1.6E-02	0.14
Ethylene dichloride	4.0E-05	1.5E-02	0.13
Ethylene dibromide	1.2E-06	4.6E-04	0.00
Formaldehyde	2.4E-04	9.2E-02	0.81
Hexane	6.7E-05	2.6E-02	0.23
Isophorone	5.8E-04	2.2E-01	1.96
Methyl bromide	1.6E-04	6.2E-02	0.54
Methyl chloride	5.3E-04	2.0E-01	1.79
Methyl ethyl ketone	3.9E-04	1.5E-01	1.32
Methyl hydrazine	1.7E-04	6.5E-02	0.57
Methyl methacrylate	2.0E-05	7.7E-03	0.07
Methyl tert butyl ether	3.5E-05	1.3E-02	0.12
Methylene chloride	2.9E-04	1.1E-01	0.98
Napthalene	1.3E-05	5.0E-03	0.04
Phenol	1.6E-05	6.2E-03	0.05
Propionaldehyde	3.8E-04	1.5E-01	1.28
Tetrachloroethylene	4.3E-05	1.7E-02	0.15
Toluene	2.4E-04	9.2E-02	0.81
1,1,1-Trichloroethane	2.0E-05	7.7E-03	0.07
Styrene	2.5E-05	9.6E-03	0.08
Xylenes	3.7E-05	1.4E-02	0.12
Vinyl acetate	7.6E-06	2.9E-03	0.03

Source: EPA, 1998; Tables 1.1-13 and 1.1-14.

REPRESENTATIVE EMERGENCY GENERATORS AND FIRE PUMP INFORMATION

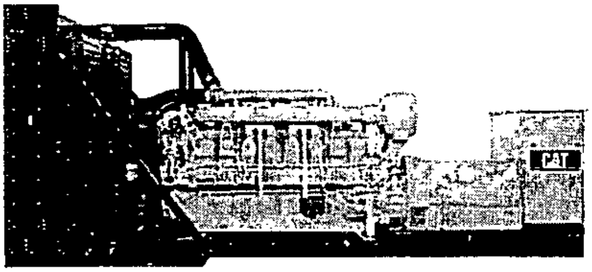


Image shown may not reflect actual package.

STANDBY

2000 ekW 2500 kVA
60 Hz 1800 rpm 480 Volts

Caterpillar is leading the power generation marketplace with Power Solutions engineered to deliver unmatched flexibility, expandability, reliability, and cost-effectiveness.

FEATURES

EMISSIONS STRATEGY

EPA Tier 2

UL 2200

- UL 2200 Listed configuration available

FULL RANGE OF ATTACHMENTS

- Wide range of bolt-on system expansion attachments, factory designed and tested

WORLDWIDE PRODUCT SUPPORT

- Caterpillar® dealers provide extensive post sale support including maintenance and repair agreements • Caterpillar dealers fill 99.7% of parts orders within 24 hours • Caterpillar dealers have over 1,600 dealer branch stores operating in 200 countries • The Cat® S•O•S℠ program cost effectively detects internal engine component condition, even the presence of unwanted fluids and combustion by-products

CAT 3516C TA DIESEL ENGINE

- Reliable, rugged, durable design
- Field-proven in thousands of applications worldwide
- Four-stroke-cycle diesel engine combines consistent performance and excellent fuel economy with minimum weight

CAT SR4B Generator

- Matched to the performance and output characteristics of Caterpillar engines
- 2/3 winding
- Single point access to accessory connections
- UL 1446 recognized Class H insulation

CAT EMCP3 CONTROL PANELS

- Controls designed to meet individual customer needs:
- EMCP 3 provides the option for full-featured power metering and protective relaying
- Segrated low voltage, AC/DC accessory box provides single point access to accessory connections

STANDBY 2000 ekW 2500 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR

FACTORY INSTALLED STANDARD & OPTIONAL EQUIPMENT

System	Standard	Optional
Air Inlet	• Single element canister type air cleaner • Service indicator	• Dual element & heavy duty air cleaners (with pre-cleaners) • Air inlet adapters & shutoff
Cooling	• Radiator with guard (43°C) • Coolant drain line with valve • Fan and belt guards • Caterpillar Extended Life Coolant • Low coolant level & high temperature alarm or shutdown	• Radiator duct flange • Jacket water heater
Exhaust	• Dry exhaust manifold • Flanged faced outlets	• Mufflers and Silencers • Stainless steel exhaust flex fittings • Elbows, flanges, expanders & Y adapters
Fuel	• Secondary fuel filters • Fuel priming pump • Flexible fuel lines • Fuel cooler* *Not included with packages without radiators	• Water separator • Duplex fuel filter
Generator SR4B	• Permanent magnet excited • 2/3 Pitch • Class H insulation • Class F temperature (105°C prime/130°C standby) • Winding temperature detectors(select models)	• Oversize & premium generators • Anti-condensation space heaters • Bearing temperature detector • Stator temperature detector
Power Termination	• Bus bar (NEMA and IEC meachanicallug holes) -right side standard • Top and bottom cable entry	• Circuit breakers, UL listed, 3 pole with shunt trip, 80% or 100% rated, choice of trip units, manual or electrically operated (low voltage only) • Circuit breakers, IEC compliant, 3 or 4 pole with shunt trip (low voltage only), choice of trip units, manual or electrically operated • Shroud cover for bottom cable entry • Power terminations can be located on the left and/or rear as an option. Also, multiple circuit breakers can be ordered (up to 3)
Governor	• ADEM™ 3	• Load share module
Control Panels	• User Interface panel (UIP) - rear mount (standard) • EMCP3.1 Genset Controller • Speed adjust (on panel) • AC&DC customer wiring area (right side) • CAT digital voltage regulator (CDVR) with KVAR/PF control, 3-phase sensing • Emergency Stop Pushbutton	• EMCP 3.3 • Option for right or left mount UIP • Local & remote annunciator modules • Load share module • Discrete I/O module • Generator temperature monitoring & protection • Voltage Adjust (on panel)
Lube	• Lubricating oil and filter • Oil drain line with valves • Fumes disposal • Gear type lube oil pump	• Oil level regulator • Deep sump oil pan • Electric & air prelube pumps • Manual prelube with sump pump • Duplex oil filter
Mounting	• Structual steel tube • Anti-vibration mounts (shipped loose)	• Isolator removal
Starting/Charging	• 24 volt starting motor(s) • Batteries with rack and cables • Battery disconnect switch	• Battery chargers (10&20AMP) •45 amp charging alternator • Oversize batteries • Ether starting aid • Heavy duty starting motors • Barring device (manual) • Air starting motor with control & silencer
General	• Right-hand service • Paint - Caterpillar Yellow except rails and radiators are gloss black • SAE standard rotation • Flywheel and flywheel housing - SAE No. 00	• CSA certification • EU Certificate of Conformance
Note	Standard and optional equipment may vary for UL 2200 Listed Packages. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.	

STANDBY 2000 ekW 2500 kVA

60 Hz 1800 rpm 480 Volts

CATERPILLAR®

SPECIFICATIONS

CAT GENERATOR

Frame	825
Excitation	Permanent Magnet
Pitch	0.6667
Number of poles	4
Number of bearings	Single Bearing
Insulation	UL 1446 Recognized Class H with tropicalization and antiabrasion
IP Rating	Drip Proof IP22
Alignment	Pilot Shaft
Overspeed capability	125%
Wave form	2%
Paralleling kit/Droop transformer	Standard
Voltage regulator	3 Phase sensing with selectible volts/Hz
Voltage regulation	Less than +/- 1/2% (steady state) Less than +/- 1/2% (w/3% speed change)
Telephone influence factor	Less than 50
Harmonic distortion	Less than 5%

CAT DIESEL ENGINE

Bore	170.00 mm (6.69 in)
Stroke	190.00 mm (7.48 in)
Displacement	69.00 L (4210.64 in³)
Compression Ratio	14.7:1
Aspiration	TA
Fuel System	Electronic unit injection
Governor Type	ADEM3

CAT EMCP3 CONTROL PANELS

EMCP 3.1 (standard)
EMCP 3.2 & 3.3 (Optional)
24 Volt DC control
Generator insturments designed to meet UL/CSA/CE
Integral generator terminal box
Single location for customer connection
MODBUS isolated data link (RS0485 half-duplex) supports serial communication at data rate up to 33.6 kbaud
Auto start/stop control
True RMS metering, 3-phase
• Digital indication for:
-RPM
-Operating hours
-Oil pressure
-Coolant temperature
\- System DC volts
--L-L volts, L-N volts, phase amps, Hz
-Ekw, kVA, kVAR, kW-hr, %kW, PF
• Shutdowns with indicating lights for:
-Low oil pressure
-High coolant temperature
\- Low coolant level
\- Overspeed
-Overspeed
-Emergency stop
\- Failure to start (over crank)
• Programmable protective relay functions:
\- Under and over voltage
\- Under and over frequency
\- Reverse power
\- Overcurrent (phase & total)
-• Programmable kW level relay

STANDBY 2000 ekW 2500 kVA

60 Hz 1800 rpm 480 Volts

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8263	
EPA Tier 2		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	2500 kVA	
Genset Power rating with fan	2000 ekW	
Coolant to aftercooler		
Coolant to aftercooler temp max	50 ° C	122 ° F
Fuel Consumption		
100% load with fan	525.7 L/hr	138.9 Gal/hr.
75% load with fan	408.2 L/hr	107.8 Gal/hr.
50% load with fan	294.2 L/hr	77.7 Gal/hr
Cooling System[1]		
Ambient air temperature	46 ° C	115 ° F
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	2480 m^3/min	87580 cfm
Engine Coolant capacity with radiator/exp. tank	475.0 L	125.5 gal
Engine coolant capacity	233.0 L	61.6 gal
Radiator coolant capacity	242.0 L	63.9 gal
Inlet Air		
Combustion air inlet flow rate	180.3 m^3/min	6367.2 cfm
Exhaust System		
Exhaust stack gas temperature	405.4 ° C	761.7 ° F
Exhaust gas flow rate	428.6 m^3/min	15135.9 cfm
Exhaust flange size (internal diameter)	203.2 mm	8.0 in
Exhaust system backpressure (maximum allowable)	6.2 kPa	24.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	765 kW	43505 Btu/min
Heat rejection to exhaust (total)	1804 kW	102593 Btu/min
Heat rejection to aftercooler	666 kW	37875 Btu/min
Heat rejection to atmosphere from engine	137 kW	7791 Btu/min
Heat rejection to atmosphere from generator	74.7 kW	4248.2 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	4647 skVA	
Frame	825	
Temperature Rise	130 ° C	266 ° F
Lube System		
Sump refill with filter	401.3 L	106.0 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.39 g/hp-hr	
CO g/hp-hr	.29 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.026 g/hp-hr	

[1] Ambient capability at 300 m (984ft) above sea level. For ambient capability at other altitudes, consult your Caterpillar dealer.

[2] UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics. Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32.

[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77°F, 28.42 in HG and number 2 diesel fuel with 35° API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

RATING DEFINITIONS AND CONDITIONS

Meets or Exceeds International Specifications: AS1359, AS2789, CSA, EGSA101P,IEC60034, ISO3046, ISO8528,NEMA MG 1-32, UL508, 72/23/EEC, 89/336/EEC, 98/37/EEC.

Standby -Output available with varying load for the duration of the interruption of the normal source power. Standby power in accordance with ISO8528. Fuel stop power in accordance with ISO3046, AS2789, and BS5514. Standby ambient temperatures shown indicate a coolant top tank temperature just below shutdown at 100 percent load.

Prime - Output available with varying load for an unlimited time. Prime power in accordance with ISO8528. 10% overload power in accordance with ISO3046, AS2789, and BS5514. Prime ambient temperatures shown indicate a coolant top tank temperature just below shutdown at 100 percent load.

Ratings are based on SAE J1995 standard conditions. These ratings also apply at ISO3046 standard conditions.

Fuel Rates are based on fuel oil of 35° API [16° C (60° F)] gravity having an LHV of 42 780 kJ/kg (18,390 Btu/lb) when used at 29° C (85° F) and weighing 838.9 g/liter (7.001 lbs/U.S. gal.). Additional ratings may be available for specific customer requirements. Consult your Caterpillar representative for details.

DIMENSIONS

Package Dimensions		
Length	**6424.6 mm**	**252.94 in**
Width	**2450.2 mm**	**96.46 in**
Height	**2929.2 mm**	**115.32 in**
Weight	**17 307 kg**	**38,155 lb**

Note: Do not use for installation design.
See general dimension drawings for
detail (Drawing #2846051).

Performance No.: DM8263

Feature Code:: 516DE5A

Source:: U.S. Sourced

29 August 2006

www.CAT-ElectricPower.com

CATERPILLAR® **C15 ACERT ™** **403 bkW / 540 bhp**

2100 rpm

Industrial

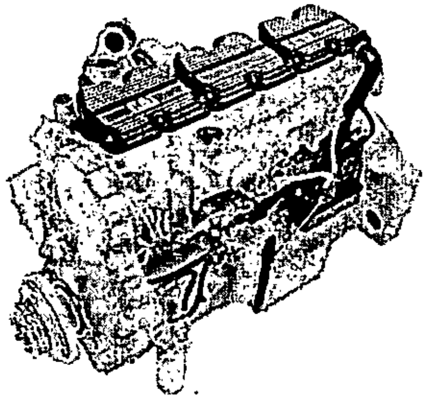


Image shown may not reflect actual engine

CATERPILLAR ENGINE SPECIFICATIONS

I-6, 4-Stroke-Cycle Diesel

Bore	137.2 mm (5.4 in)
Stroke	171.4 mm (6.75 in)
Displacement	15.2 L (927.56 in^3)
Aspiration	Turbocharged Aftercooled
Compression Ratio	18:1
Rotation (from flywheel end)	Counterclockwise
Weight, Net Dry (approximate kg. lb)	1332 kg, 2937 lb

FEATURES

Emissions

Meets Tier 3, Stage IIIA emission requirements. Tier 3 refers to EPA (U.S.) standards. Stage IIIA refers to European standards.

Worldwide Supplier Capability

Caterpillar
- Casts engine blocks, heads, cylinder liners, and flywheel housings
- Machines critical components
- Assembles complete engine
- Factory-designed systems built at Caterpillar ISO 9001:2000 certified facilities

Ownership of these manufacturing processes enables Caterpillar to produce high quality, dependable product.

Testing

Prototype testing on every model:
- proves computer design
- verifies system torsional stability
- functionality tests every model

Every Caterpillar engine is dynamometer tested under full load to ensure proper engine performance.

Full Range of Attachments

Wide range of bolt-on system expansion attachments, factory designed and tested.

Unmatched Product Support Offered Through Worldwide Caterpillar Dealer Network

More than 1,800 dealer outlets
Caterpillar factory-trained dealer technicians service every aspect of your industrial engine
99.7% of parts orders filled within 24 hours worldwide
Caterpillar parts and labor warranty
Preventive maintenance agreements available for repair before failure options

Scheduled Oil Sampling program matches your oil sample against Caterpillar set standards to determine:
- internal engine component condition
- presence of unwanted fluids
- presence of combustion by-products

Web Site

For all your industrial power requirements, visit www.cat-industrial.com.

STANDARD ENGINE EQUIPMENT

Air Inlet System

ATAAC
Turbocharged

Control System

Electronic governing
PTO speed control
Programmable ratings
Cold mode start strategy
Automatic altitude compensation
Power compensation for fuel temperature
Programmable low and high idle and total engine limit
Electronic diagnostics and fault logging
Engine monitoring system
J1939 Broadcast (diagnostic and engine status)
ADEM™ A4

Cooling System

Thermostats and housing, vertical outlet
Jacket water pump, centrifugal
Water pump, inlet

Exhaust System

Exhaust manifold, dry
Optional exhaust outlet

Flywheels and Flywheel Housing

SAE No. 1 Flywheel housing

Fuel System

MEUI injection
Fuel filter, secondary (2 micron high performance)
Fuel transfer pump
Fuel priming pump
ACERT™ Technology

Lube System

Crankcase breather
Oil cooler
Oil filler
Oil filter
Oil pan front sump
Oil dipstick
Oil pump (gear driven)

General

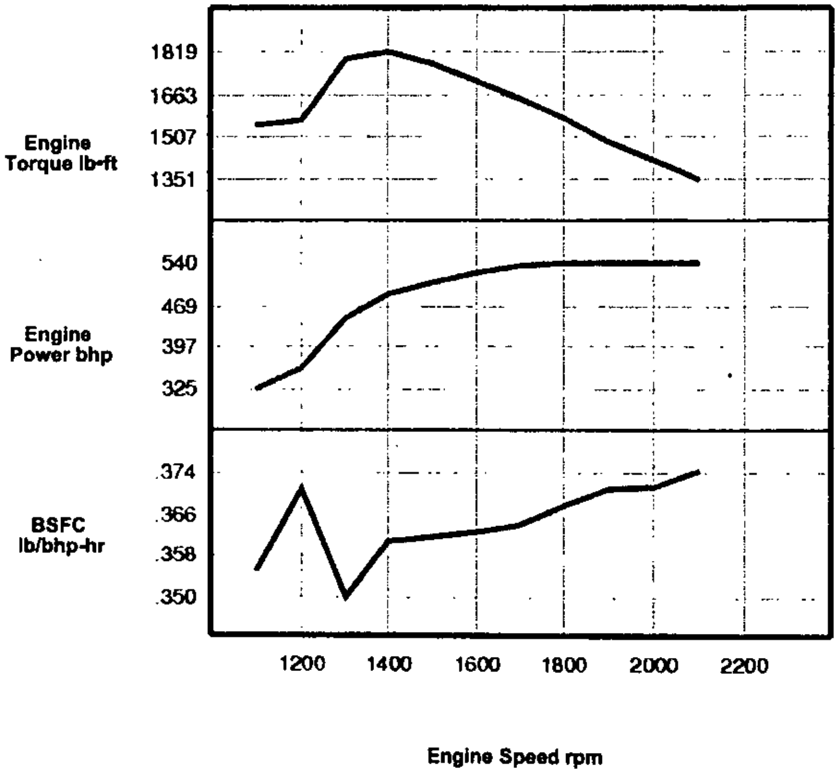
Paint, Caterpillar Yellow
Vibration damper
Lifting eyes

CATERPILLAR® C15 ACERT™ INDUSTRIAL ENGINE

403 bkW (540 bhp)

PERFORMANCE CURVES

IND - C (Intermittent) - DM7520-01



English

Engine Speed rpm	Engine Power bhp	Engine Torque lb-ft	BSFC lb/bhp-hr	Fuel Rate gal/hr
2100	540	1351	.374	28.9
2000	540	1419	.371	28.7
1900	540	1494	.371	28.6
1800	540	1577	.368	28.4
1700	534	1649	.364	27.8
1600	522	1715	.363	27.1
1500	506	1773	.362	26.2
1400	485	1819	.361	25.0
1300	444	1795	.350	22.2
1200	360	1574	.371	19.0
1100	325	1550	.355	16.5

CATERPILLAR®

C15 ACERT ™

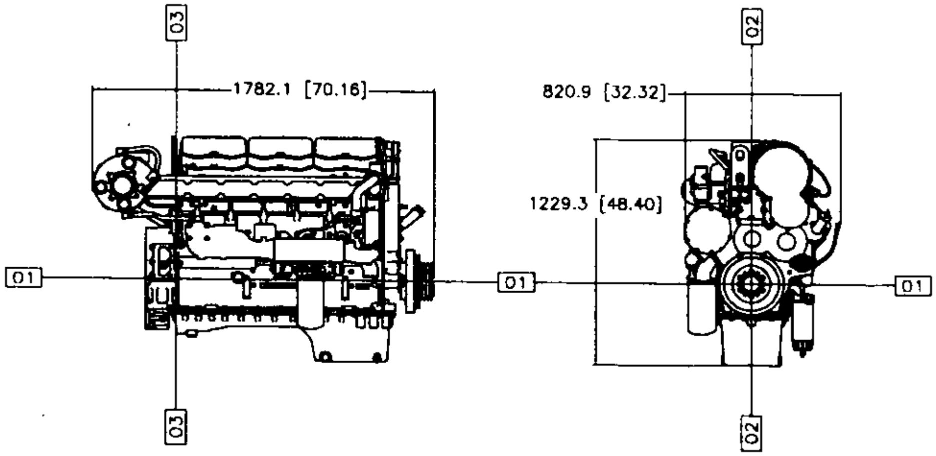
INDUSTRIAL ENGINE

403 bkW (540 bhp)

RATINGS AND CONDITIONS

IND - C (Intermittent) Intermittent service where maximum power and/or speed are cyclic (time at full load not to exceed 50%).

Engine Performance Diesel Engines — 7 liter and higher
All rating conditions are based on SAE J1995, inlet air standard
conditions of 99 kPa (29.31 in. Hg) dry barometer and 25°C (77°F)
temperature. Performance measured using a standard fuel with fuel
gravity of 35° API having a lower heating value of 42,780 kJ/kg
(18,390 btu/lb) when used at 29° C (84.2° F) with a density of 838.9 g/L.



Engine Dimensions	
(1) Length	54.37 in
(2) Width	35.84 in
(3) Height	50.18 in

Note: Do not use for installation design. See general dimension drawings for detail (Drawing # 2579952).

Performance Number: DM7520-01

Feature Code: C15DI12

Materials and specifications are subject to change without notice.

8677722

The International System of Units (SI) is used in this publication.

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY

TABLE B-1
RECENTLY PERMITTED SCPC AND PC PROJECTS

Project	Date	Status	Plant Size MW	Type
Seminole Electric Unit 3 - Flroida	Aug-06	Draft Permit	750	SCPC
Thoroughbred - Kentucky	May-06 (Revision)	Final Permit	1,500	PC
Louisville Gas & Electric - Kentucky	Jan-06 (Revision)	Final Permit	750	SCPC
Prairie State-Illinois	Apr-05	Final Permit	1,500	PC
Elm Road-Wisconsin	Jan-04	Final Permit	1,830	SCPC
Longview-West Virginia	Mar-04	Final Permit	600	PC
City Public Service-Texas	Sep-05	Draft Permit	750	PC
Public Service of Colorado	Jul-05	Final Permit	1,410	PC
Public Service Corp Wausau - Wisconsin	Oct-04	Final Permit	500	SCPC
NRG Energy (Big Cajun II) - Louisiana	Aug-05	Final Permit	575	SCPC
Southwest Springfield - Missouri	Dec-04	Final Permit	275	PC
Omaha Public Power - Nebraska	March-05	Final Permit	660	PC
Municipal Energy Hastings - Nebraska	March-04	Final Permit	220	PC
Xcel Energy - Colorodo	July-05	Final Permit	750	SCPC
Bull Mountain - Montana	July-03	Final Permit	780	PC
Intermountain Power Service - Utah	Oct-04	Final Permit	950	PC
Springerville Generating Station Units 3 and 4 - Arizona	April-02	Final Permit	800	PC
TS Power Plant - Nevada	May-05	Final Permit	200	PC
MidAmerican Energy - Iowa	Jun-03	Final Permit	750	SCPC
Montana Dakota Utilities - North Dakota	Jun-05	Final Permit	220	PC
Newmont - Nevada	May-05	Final Permit	200	PC
Sand Sage - Kansas	Oct-02	Final Permit	660	PC
KCP&L Latan Generating - Missouri	Jan-06	Final Permit	850	PC

TABLE B-2
NITROGEN OXIDES EMISSIONS RATES FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled NO_x lb/MMBtu	Comments
Thoroughbred - Kentucky	1,500	14,886	0.07	SCR
Louisville Gas & Electric - Kentucky	750	6,942	0.11	SCR - Not BACT, PSD Avoided
Prairie State-Illinois	1,500	14,900	0.07	SCR
Elm Road-Wisconsin	1,230	12,360	0.07	SCR
Longview-West Virginia	600	6,114	0.08	SCR
City Public Service-Texas	750	8,000	0.069	SCR; 0.05 lb/MMBtu (0.53 lb/MW-hr)-Annual
Public Service of Colorado	750	7,421	0.08	SCR; 0.07 lb/MMBtu - Annual Limit
Public Service Corp Wausau - Wisconsin	500	5176	0.06	LNB/SCR
NRG Energy - Louisiana	575	6566	0.071	LNB/SCR
Southwest Springfield - Missouri	275	2725	0.08	SCR
Omaha Public Power - Nebraska	660	NA	0.07	SCR
Municipal Energy Hastings - Nebraska	220	2210.5	0.08	SCR
Xcel Energy - Colorado	750	7421	0.08	SCR - Net out of PSD Review
Bull Mountain - Montana	780	8026	0.1 0.07	1-hr, SCR 24-hr
Intermountain Power Service - Utah	950	9050	0.07	SCR
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	See Comment	Facility Emission CAP Units 1, 2, 3, and 4. 9,600 tpy, LNB and SCR
TS Power Plant - Nevada	200	2030	0.067	LNB an SCR
MidAmerican Energy - Iowa	750	-	0.07	SCR
Montana Dakota Utilities - North Dakota	220	2,116	0.09	30-day average
Newmont - Nevada	200	2,030	0.064	SCR
Sand Sage - Kansas	660	6,501	0.08	LNB, SOFA, SCR
KCP&L - Missouri	850	7,800	0.08	SCR

TABLE B-3
PM/PM10 EMISSIONS RATES FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled PM/PM$_{10}$ lb/MMBtu	Opacity Limits %	Comments
Seminole Electric Unit 3 - Florida	750	7,500	0.013	20	Filterable (100% coal), ESP and WESP
Thoroughbred - Kentucky	1,500	14,886	0.018	20	ESP and WESP - opacity 6-minute average
Louisville Gas & Electric - Kentucky	750	6,942	0.018	20	Pulse Jet Fabric Filter (0.015 lb/MMBtu filterable) - opacity 6-minute average
Prairie State-Illinois	1,500	14,900	0.015	20	ESP - opacity 6-minute average
Elm Road-Wisconsin	1,230	12,360	0.018	20	Fabric Filter; 20% opacity
Longview-West Virginia	600	6,114	0.018 0.018	10	Fabric Filter PM10 w/condensible
City Public Service-Texas	750	8,000	0.022		Fabric Filter; includes condensible
Public Service of Colorado	750	7,421	0.013 0.022 0.012 0.02	10	PM Fabric Filter; 10% opacity PM w/condensable PM10 Filterable PM10 w/condensable
Public Service Corp Wausau - Wisconsin	500	5,176	0.02 0.018	40	PM (Total), Fabric Filter w/condensable PM10 - Filterable and Condensable
NRG Energy - Louisiana	575	6,566	0.018 0.015		ESP and Fabric Filter PM
Southwest Springfield - Missouri	275	2,725	0.018		Fabric Filter
Omaha Public Power - Nebraska	660	NA	0.018		Fabric Filter
Municipal Energy Hastings - Nebraska	220	2,211	0.018	≥20	Fabric Filter
Xcel Energy Comanche Station - Colorado	750	7,421	0.012 0.013 0.022	20	PM10 (Filterable) Fabric Filter PM (Filterable) PM (Total)
Bull Mountain - Montana	780	8,026	0.015		PM (Filterable)
Intermountain Power Service - Utah	950	9,050	0.012 0.013 0.024	20	PM10 (Filterable) Fabric Filter PM (Filterable) PM (Total)
Springerville Generating Station Units 3 and 4 - Arizona	800	8,400	0.015 0.055	15	PM10 (Filterable), Fabric Filter PM10 (Filterable and condensable)
TS Power Plant - Nevada	200	2,030	0.012		Fabric Filter
MidAmerican Energy - Iowa	750	-	0.027 0.018 0.025	40	PM w/condensible PM filterable PM10 w/condensible
Montana Dakota Utilities - North Dakota	220	2,116	0.0167 0.013 0.0275		PM filterable PM10 filterable PM10 w/condensible
Newmont - Nevada	200	2,030	0.012	≥20	PM10 filterable
Sand Sage - Kansas	660	6,501	0.015 0.035	20	Fabric Filter PM PM10: 6 test runs of 120 minutes each
KCP&L - Missouri	850	7,800	0.024 0.014 0.015	20	PM10 Filterable and Condensable Filterable PM10 Filterable PM

TABLE B-4
SULFUR DIOXIDE EMISSIONS RATES FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Uncontrolled SO_2 lb/MMBtu	Controlled SO_2 lb/MMBtu	Removal	Comments
Thoroughbred - Kentucky	1,500	14,886	NA	0.41	99%	Wet FGD
Louisville Gas & Electric - Kentucky	750	6,942	NA	0.2161	99%	Wet FGD not BACT, PSD Avoided
Prairie State-Illinois	1,500	14,900	9.11	0.420	95.39%	Wet FGD; Initial Limit
	1,500	14,900	9.11	0.329	96.39%	Wet FGD; After 12-months
	1,500	14,900	9.11	0.181	98.01%	Wet FGD; Not lower than; performance evaluation
Elm Road-Wisconsin	1,230	12,360	4.00	0.15	96.25%	Wet FGD; 2.5% Sulfur Coal and 5% ash
Longview-West Virginia	600	6,114	4.00	0.15	96.25%	Wet FGD; 2.5% sulfur coal; 3-hour
	600	6,114	4.00	0.12	97.00%	Wet FGD; 24-hour
City Public Service-Texas	750	8,000	1.25	0.1-0.06	95%	Wet FGD; 0.06 lb/MMBtu-Annual
Public Service of Colorado	750	7,421	1.30	0.1	92.31%	Dry Scrubber; PRB Coal; uncontrolled SO_2 estimated
Public Service Corp Wausau - Wisconsin	500	5176	NA	0.06	NA	Dry FGD
NRG Energy - Louisiana	575	6566	NA	0.1	NA	Wet Scrubber
Southwest Springfield - Missouri	275	2725	NA	0.095	NA	DLS/SDA-PRB Coal
Omaha Public Power - Nebraska	660	NA	NA	0.095	NA	DLS/SDA-PRB Coal
Municipal Energy Hastings - Nebraska	220	2210.5	NA	0.12	NA	DLS/SDA-PRB Coal
Xcel Energy - Colorodo	750	7421	NA	0.1	NA	Dry FGD - Net out of PSD Review
Bull Mountain - Montana	780	8026	NA	0.15	NA	1-hr, Dry FGD
				0.12	NA	12-hr
Intermountain Power Service - Utah	950	9050	NA	0.1	NA	24-hr Average, Dry Lime Scrubber
				0.09		30-day Average
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	See Comment	See Comment	NA	Facility Emission CAP Units 1, 2, 3, and 4. 10,800 tpy, SDA
TS Power Plant - Nevada	200	2030	NA	0.09	95%	95% Control When S content > 0.45%. Dry Scrubber
MidAmerican Energy - Iowa	750	-	-	0.10	-	30-day rolling average
Montana Dakota Utilities - North Dakota	220	2,116	3.48	0.036	90%	30-day rolling average
Newmont - Nevada	200	2,030	-	-		
Sand Sage - Kansas	660	6,501	NA	0.12	NA	Dry FGD, max fuel sulfur content - 0.60%
KCP&L - Missouri	850	7,800	NA	0.10	NA	Wet FGD, Low sulfur coal less than 1.4 lb/MMBtu SO2: 4,212 lb/hr 24-hr, 6,630 lb/hr 3-hr

TABLE B-5
SULFURIC ACID MIST EMISSIONS RATES FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled SAM lb/MMBtu	Comments
Thoroughbred - Kentucky	1,500	14,886	0.00497	WESP
Louisville Gas & Electric - Kentucky	750	6.942	0.00383	WESP
Prairie State-Illinois	1,500	14,900	0.005	WESP
Elm Road-Wisconsin	1,230	12,360	0.01	WESP
Longview-West Virginia	600	6,114	0.0075	Dry sorbent injection, no WESP
City Public Service-Texas	750	8,000	0.0037	Wet FGD; no WESP
Public Service of Colorado	750	7,421	0.0042	PRB Coal; no WESP
Public Service Corp Wausau - Wisconsin	500	5176	0.005	FGD
NRG Energy - Louisiana	575	6566	NA	NA
Southwest Springfield - Missouri	275	2725	0.000184	DLS/SDA-PRB Coal
Omaha Public Power - Nebraska	660	NA	0.0042	DLS/SDA-PRB Coal
Municipal Energy Hastings - Nebraska	220	2210.5	NA	NA
Xcel Energy - Colorado	750	7421	0.0042	Dry FGD
Bull Mountain - Montana	780	8026	0.0064	Dry FGD
Intermountain Power Service - Utah	950	9050	0.0044	Dry Lime Scrubber
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	See Comment	Facility Emission CAP Units 1, 2, 3, and 4. 211 tpy, SDA
TS Power Plant - Nevada	200	2030	NA	NA
MidAmerican Energy - Iowa	750	-	0.00421	Dry Lime Scrubber
Montana Dakota Utilities - North Dakota	220	2,116	-	6.14 lb/hr
Newmont - Nevada	200	2,030	-	
Sand Sage - Kansas	660	6,501	NA	
KCP&L - Missouri	850	7,800	0.0072	

TABLE B-6
CO AND VOC EMISSIONS RATES FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled CO lb/MMBtu	Controlled VOC lb/MMBtu	Comments
Seminole Electric Unit 3 - Flroida	750	7,500	0.13 0.15	0.0034	Coal Only, Combustion Controls 30-day Average All Fuels
Thoroughbred - Kentucky	1,500	14,886	0.1	0.0072	Combustion Controls
Louisville Gas & Electric - Kentucky	750	6,942	0.1/0.5	0.0032	CO 30-day/3-hour average, VOC 3-hr Average, Combustion Controls
Prairie State-Illinois	1,500	14,900	0.12	0.004	Combustion Controls
Elm Road-Wisconsin	1,230	12,360	0.12	0.0035	Combustion Controls
Longview-West Virginia	600	6,114	0.11	0.004	Combustion Controls
City Public Service-Texas	750	8,000	0.15	0.0036	Combustion Controls
Public Service of Colorado	750	7,421	0.13	0.0035	Combustion Controls
Public Service Corp Wausau - Wisconsin	500	5176	0.15	0.0036	Combustion Controls
NRG Energy - Louisiana	575	6566	0.135	0.015	Combustion Controls
Southwest Springfield - Missouri	275	2725	0.16	0.0036	Combustion Controls
Omaha Public Power - Nebraska	660	NA	0.16	0.0034	Combustion Controls
Municipal Energy Hastings - Nebraska	220	2210.5	0.15	NA	Combustion Controls
Xcel Energy - Colorodo	750	7421	0.13	0.0035	Combustion Controls
Bull Mountain - Montana	780	8026	0.15	0.003	Combustion Controls
Intermountain Power Service - Utah	950	9050	0.15	0.0027	Combustion Controls
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	0.15	See Comment	VOC limit = 0.06 lb/ton coal combusted, Combustion Controls
TS Power Plant - Nevada	200	2030	0.15	NA	Combustion Controls
MidAmerican Energy - Iowa	750	-	0.154	0.0036	Combustion Controls
Montana Dakota Utilities - North Dakota	220	2,116	0.154	0.005	3-hr average
Newmont - Nevada	200	2,030	0.15	NA	24-hr rolling
Sand Sage - Kansas	660	6,501	0.15	0.0035	Combustion Controls
KCP&L - Missouri	850	7,800	0.14	0.0036	Combustion Controls

TABLE B-7
TOTAL FLUORIDES EMISSIONS RAETS FROM RECENTLY PERMITTED PROJECTS

Project	Plant Size MW	Heat Input MMBtu/hr	Controlled Fluorides lb/MMBtu	Comments
Seminole Electric Unit 3 - Florida	750	7,500	0.00023	Wet FGD and WESP
Thoroughbred - Kentucky	1,500	14,886	0.000159	Wet FGD and WESP
Louisville Gas & Electric - Kentucky	750	6,942	0.000223279	WFGD
Prairie State-Illinois	1,500	14,900	0.00026	Wet FGD and WESP
Elm Road-Wisconsin	1,230	12,360	0.00088	Wet ESP
Longview-West Virginia	600	6,114	0.00001	Dry sorbent injection, no WESP
City Public Service-Texas	750	8,000	0.0008	Wet FGD; no WESP
Public Service of Colorado	750	7,421	0.00049	As HF
Public Service Corp Wausau - Wisconsin	500	5176	0.000217	Sobent Injection/FF
NRG Energy - Louisiana	575	6566	NA	NA
Southwest Springfield - Missouri	275	2725	0.00037	Synthetic minor for HAPs
Omaha Public Power - Nebraska	660	NA	0.0004	NA
Municipal Energy Hastings - Nebraska	220	2210.5	0.0004	NA
Xcel Energy - Colorado	750	7421	0.00049	NA
Bull Mountain - Montana	780	8026	NA	NA
Intermountain Power Service - Utah	950	9050	0.0005	Co benefit Controls
Springerville Generating Station Units 3 and 4 - Arizona	800	8400	0.00044	Co benefit Controls
TS Power Plant - Nevada	200	2030	NA	NA
MidAmerican Energy - Iowa	765	-	0.0009	Co benefit Controls
Montana Dakota Utilities - North Dakota	220	2,116	0.00053	
Newmont - Nevada	200	2,030	NA	
Sand Sage - Kansas	660	6,501	NA	
KCP&L - Missouri	850	7,800	-	33.15 lb/hr Three test runs