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Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL

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SEP 30 1992

Division of Air
Resources Management

RE: Sol-Energy PSD Permit Application

Dear Mr. Fancy:

On behalf of Okeelanta Corporation, please find enclosed eight (8) copies of the PSD permit application for the Sol-Energy cogeneration facility proposed to be located in Palm Beach County. This application is a "sister" application to the Flo-Energy application submitted to the Department on September 17, 1992. Also enclosed is the application fee of \$7,500.

We look forward to the Department's review of the application, and welcome any comments or questions you or your staff may have.

Sincerely,

David A. Buff, M.E., P.E.
Principal Engineer

DAB/tyf

cc: Gus Cepero
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12118D1/1

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OSCEOLA FARMS CO.
PAHOKEE, FLORIDA

013519

MEMO	DISTRIBUTION	INVOICE NO.	INV. DATE	BATCH NO.	GROSS AMT.	DISCOUNT	DED. CODE	NET AMOUNT
Permit for Boiler	135/57.09.00/15				7,500.00			7,500.00

DEDUCTION
CODES

01 CASH DISCOUNT
02 ACCOUNTS RECEIVABLE
03 MISCELLANEOUS

BARNETT BANK
OF PALM BEACH COUNTY

OSCEOLA FARMS CO.

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SEP 30 1992

Division of Air
Resources Management

219795

**Air Permit Application For
SOL-ENERGY COGENERATION
FACILITY
Palm Beach County, Florida**

Prepared For:

**Sol-Energy, Inc.
316 Royal Poinciana Plaza
Palm Beach, Florida 33480**

Prepared By:

**KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605**

**September 1992
12118D1**

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EXECUTIVE SUMMARY

Sol-Energy, Inc. is proposing to install a cogeneration facility at the site of the existing Osceola Farms sugar mill located east of Pahokee, Florida, in Palm Beach County. Sol-Energy, Inc. is proposing to replace the five existing bagasse/oil-fired boilers with a cogeneration system consisting of two new spreader stoker combustion units. The cogeneration facility will use primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The new facility will provide enough steam energy for the needs of the existing sugar mill and will generate up to 74.9 megawatts of electricity which will be sold to Florida Power & Light Company. Further, the proposed facility will reduce total annual air emissions and water consumption compared to the existing facility while generating approximately 15 times more electric energy than the existing facility.

It is Sol-Energy's desire to burn 100 percent biomass fuels in the proposed facility. Generally, the bagasse from the sugar grinding operation will provide approximately two-thirds of the annual fuel requirements of the facility. The other one-third will be provided by wood waste materials, which could include clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of fossil fuel in the event that the supply of biomass fuel is not adequate. Therefore, the proposed facility will have the capability to burn biomass, fuel oil, and coal, either alone or in combination.

Any fossil fuels utilized at the facility will be limited to a combined 25 percent of the total annual heat input in any given year. Any fuel oil utilized will be very low sulfur No. 2 distillate fuel oil with a maximum sulfur content of 0.5 percent. Any coal fired in the facility will be low sulfur coal of approximately 0.7 percent sulfur content. It is emphasized that Sol-Energy does not ever intend to burn coal at the facility and will not burn coal if the biomass supply is adequate to meet the fuel requirements of the plant.

The proposed facility will utilize several emission control techniques to reduce emissions. The facility will incorporate a selective non-catalytic reduction system to reduce nitrogen oxide

emissions. Carbon monoxide and volatile organic compound emissions will be minimized through proper furnace design and good combustion practices. Particulate emissions will be reduced by an electrostatic precipitator (ESP). Mercury emissions will be controlled through a carbon injection system (or equivalent) and the ESP system.

This report addresses the requirements of the prevention of significant deterioration (PSD) review procedures, pursuant to the rules and regulations implementing the federal Clean Air Act Amendments of 1977. Based on the current actual emissions from the Osceola Farms facility and worst-case maximum emissions from the proposed cogeneration facility, the proposed project will result in significant reductions in several air pollutants, including particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead. Reductions in emissions of sulfur dioxide, beryllium, fluorides, and sulfuric acid mist will also occur under the anticipated case of 100 percent biomass firing. Under worst-case conditions of 25 percent coal firing during a year, increases in emissions of sulfur dioxide, fluoride, beryllium, and sulfuric acid mist will occur, requiring a PSD review for these pollutants.

However, on balance, there will be no increase in SO₂ emissions due to the proposed project. A similar cogeneration project is being proposed also for the Okeelanta sugar mill. According to the zoning approval with the Palm Beach County Planning and Zoning Board, annual SO₂ emissions for both the Sol-Energy and Flo-Energy (i.e., Osceola and Okeelanta) cogeneration facilities combined, averaged over the life of the project (estimated at 30 years), must be limited to the current combined SO₂ emissions from the existing Osceola and Okeelanta sugar mills (i.e., 1,000 tons per year).

In the case of mercury emissions, the Palm Beach County zoning approval requires that maximum annual mercury emissions for the cogeneration facility cannot exceed current annual mercury emissions, even under worst-case conditions of 25 percent coal burning. In order to meet this requirement, Sol-Energy will install a mercury control system on each of the two new cogeneration units. This is the first facility of its type in the world to employ a mercury control system.

Sol-Energy will demonstrate compliance with pollutant emission limits by monitoring continuously such parameters as steam production; fuel input rates; and stack gas opacity, nitrogen oxides (NO_x), carbon monoxide (CO), and oxygen or carbon dioxide (CO_2) content. In addition, stack testing will be performed for particulate matter (PM), NO_x , CO, SO_2 , lead, mercury, and volatile organic compounds (VOCs) every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by the Florida Department of Environmental Regulation (i.e., once every year or once every 5 years, depending upon pollutant).

A top-down BACT analysis for SO_2 was performed for the worst-case scenario where the proposed boilers fire 25 percent coal as an auxiliary fuel on an annual basis. The analysis concluded that both wet and dry scrubbing technologies are technically feasible for the facility. However, significant economic, environmental, and energy costs are associated with the two alternative scrubber options. The estimated costs for add-on SO_2 controls are unreasonable, particularly considering that the facility will not burn coal as its primary fuel; if burned, coal will be burned in limited amounts and only when the supply of biomass fuels is not adequate; and coal may never be burned at the facility. A very high capital cost would be incurred for SO_2 control equipment that may never be used. No other facility in the United States has been identified as requiring add-on SO_2 controls as BACT where the heat input due to fossil fuels was less than 30 percent. Based on these considerations, using low-sulfur (approximately 0.7 percent maximum) coal as an auxiliary fuel and limiting the use of coal to a maximum of 25 percent of the total annual heat input represents BACT for SO_2 for the Sol-Energy cogeneration project.

BACT for fluorides, beryllium, and sulfuric acid mist was determined to be the firing of low-sulfur biomass, very low sulfur fuel oil, and low sulfur coal, coupled with electrostatic precipitator technology.

The air quality impact analysis for SO_2 demonstrates that the proposed facility, even when operating under worst-case conditions of coal burning, will comply with all ambient air quality standards and PSD increments. The higher stacks associated with the new cogeneration facility, compared to the shorter stacks of the existing facility, will result in a general air quality

improvement for all pollutants. No adverse air quality impacts will result upon the Everglades National Park PSD Class I area.

1.0 INTRODUCTION

Sol-Energy, Inc. is proposing to install a cogeneration facility which will use primarily biomass (bagasse and wood waste materials) to generate steam and electricity. The cogeneration facility will be located at the site of the existing Osceola Farms sugar mill located east of Pahokee, Florida. The existing sugar mill boilers will be replaced with a cogeneration system consisting of two new combustion units.

The cogeneration facility will provide enough steam energy for the needs of the Osceola Farms sugar mill and will generate electricity which will be sold to Florida Power & Light Company (FPL). Further, the proposed facility will reduce total annual air emissions and water consumption compared to the existing facility while generating approximately 15 times more electric energy than the existing facility.

This report addresses the requirements of the prevention of significant deterioration (PSD) review procedures, pursuant to the rules and regulations implementing the federal Clean Air Act Amendments of 1977. The Florida Department of Environmental Regulation (FDER) has PSD review and approval authority in Florida. Based on the current actual emissions from the Osceola facility and future maximum emissions from the proposed cogeneration facility, a PSD review is indicated for sulfur dioxide (SO₂), fluoride (F), beryllium (Be), and sulfuric acid mist.

This PSD permit application contains seven additional sections. A complete description of the project, including air emission rates and stack parameters, is found in Section 2.0. The air quality requirements for the project and new source review applicability are discussed in Section 3.0. Ambient monitoring requirements under PSD are addressed in Section 4.0. The best available control technology (BACT) analysis is presented in Section 5.0. The air quality impact (dispersion modeling) analysis is presented in Section 6.0 and additional impacts upon soils, vegetation and visibility are described in Section 7.0. Completed construction permit application forms and supportive information are contained in the appendices.

Appendix C contains the conditions and restrictions imposed on this project by Palm Beach County during the zoning process. In accordance with Palm Beach County's Condition No. 1.f.,

Sol-Energy requests that the County's Conditions No. 1.a. through 1.e. be included in FDER's specific permit conditions for the cogeneration facility. A complete list of specific permit conditions proposed for the facility is contained in Section 8.0 of this report.

2.0 PROJECT DESCRIPTION

2.1 EXISTING OPERATIONS

Osceola Farms currently operates a sugar cane processing facility at its mill located just east of Pahokee in Palm Beach county. The mill's air emission sources consist of five boilers fired by bagasse and No. 6 fuel oil. These boilers normally operate from October through March (termed the "crop season"). During this period, the mill processes sugar cane into raw sugar.

The processing of the sugar cane produces a solid fuel byproduct, called bagasse, which is burned in the boilers to generate steam for the process. The boilers also burn No. 6 fuel oil during start-up and shutdown and at times when bagasse is not available to meet the total steam demands of the facility. Based on the current annual air emissions from the Osceola Farms facility, the facility is classified as an existing major stationary facility as defined in the Florida PSD Rules.

A regional map showing the location of the site is presented in Figure 2-1. A location map of the existing sugar mill indicating the plant property boundaries is presented in Figure 2-2. As shown, Osceola Farms owns sugar cane fields surrounding the mill in several directions. The nearest property boundary is approximately 0.5 miles from the existing sugar mill. A plot plan of the existing mill indicating the existing boilers, stacks, and buildings is presented in Figure 2-3.

2.2 PROPOSED COGENERATION FACILITY

A maximum 74.9 megawatt (MW) (gross) cogeneration system is proposed which will be used to provide steam to the Osceola Farms sugar mill, and additionally will deliver a substantial amount of electricity to FPL to supply its customers in south Florida. The proposed facility will be located immediately adjacent to the existing sugar mill (see Figure 2-2).

The proposed facility will operate with two steam boilers burning biomass (primarily bagasse and wood waste materials). The proposed facility will be designed to provide the sugar mill with an average of approximately 261,000 lb/hr of steam at 250 pounds per square inch gauge (psig) and 550°F and an average of approximately 126,000 lb/hr of steam at 20 psig and 280°F during the crop season. These steaming rates may vary as a function of operational conditions; equipment and process efficiencies; characteristics of the fuel, which is an agricultural product and somewhat

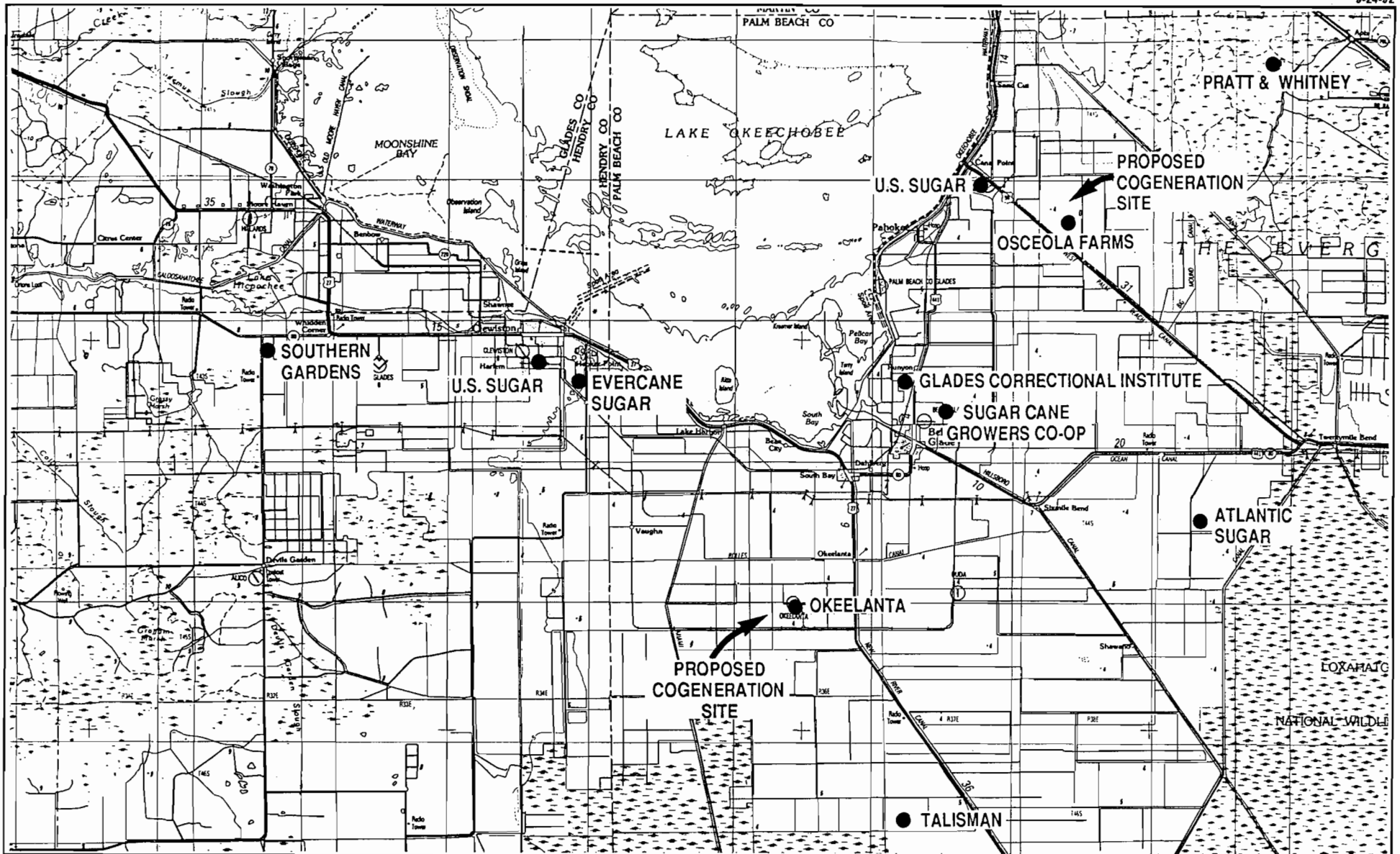


Figure 2-1 REGIONAL SITE MAP

KBN

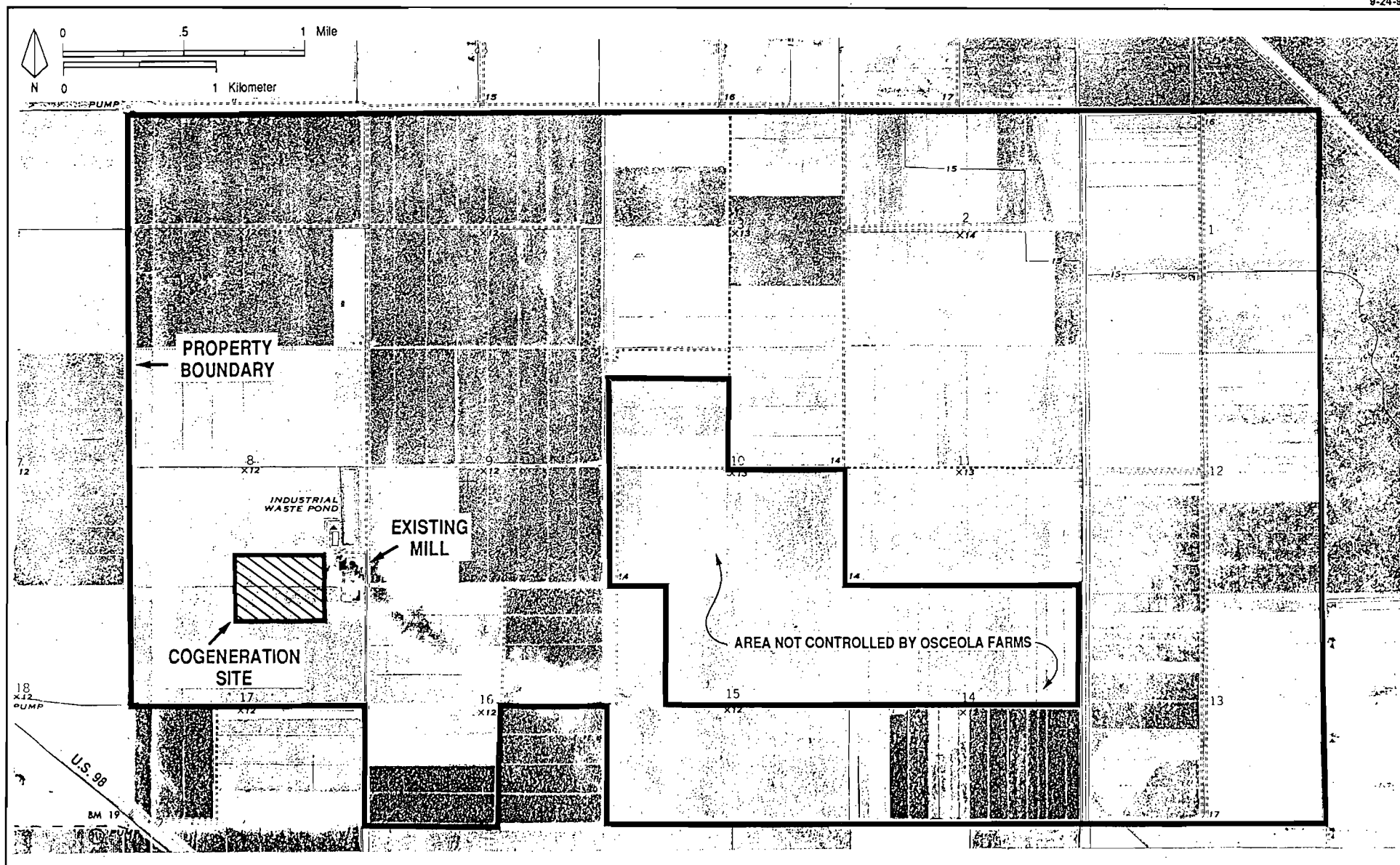


Figure 2-2 SITE LOCATION MAP

SOURCE: USGS, 1970.



KEY:

⑤ STACK LOCATION

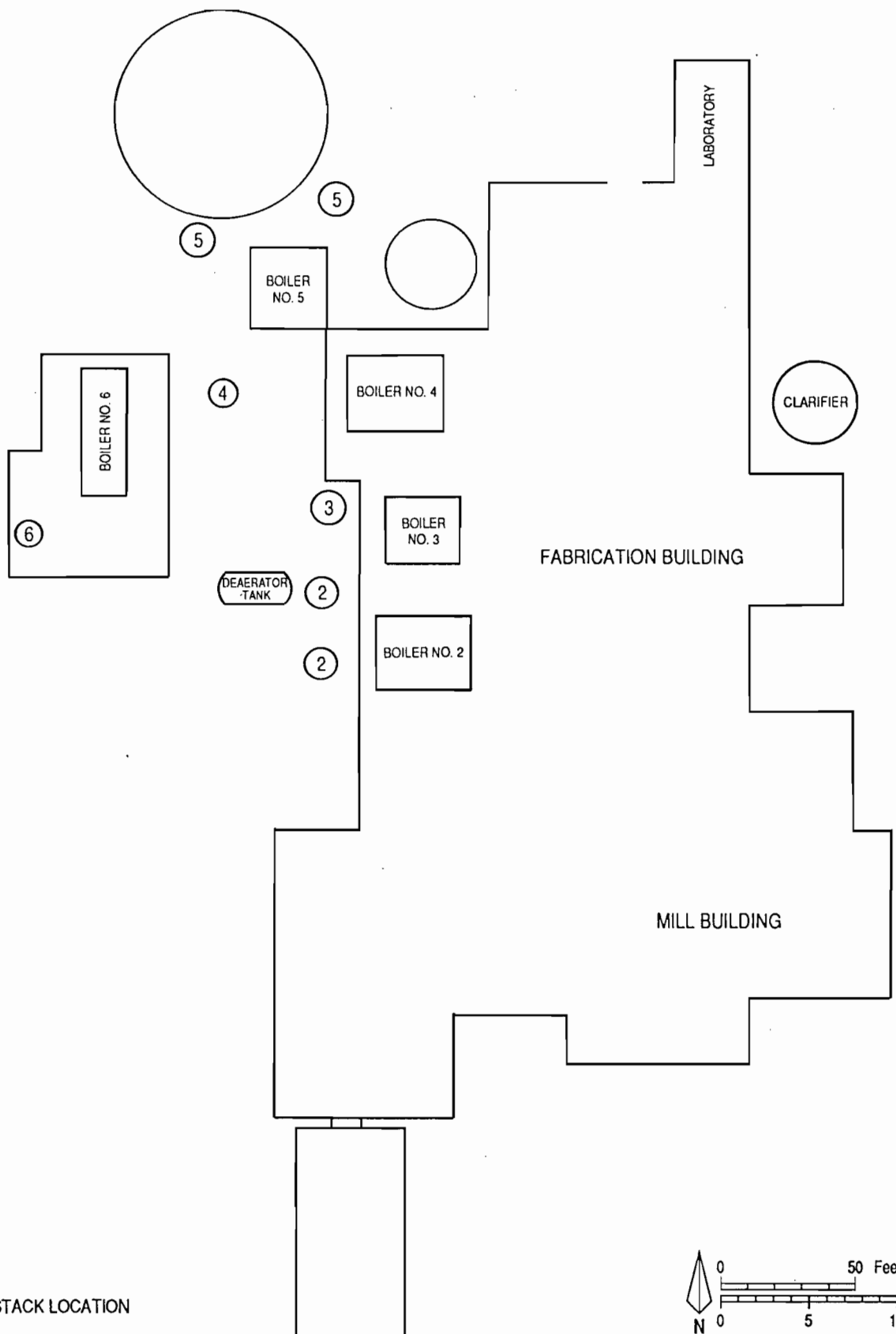


Figure 2-3 PLOT PLAN OF EXISTING OSCEOLA FARMS SUGAR MILL



variable; and overall sugar mill production rate. The proposed facility will produce up to 74.9 MW (gross) of electricity year-round. A simplified flow diagram of the process is provided in Figure 2-4.

The existing boilers will be shut down upon commercial operation of the proposed cogeneration facility. During the first 3 years of cogeneration facility operation, the existing boilers may be operated only at times when the two boilers of the new cogeneration facility are shut down for repair or maintenance. After this time, the existing boilers will be permanently disabled and made incapable of operation.

A plot plan of the proposed facility is presented in Figure 2-5. The major structures will consist of the two boiler buildings.

It is Sol-Energy's desire to burn 100 percent biomass fuels. Generally, the bagasse from the sugar grinding operation will provide approximately two-thirds of the annual fuel requirements of the facility. The other one-third will be provided by wood waste materials, which could include clean construction and demolition wood debris, yard trimmings, land clearing debris, and other clean cellulose and vegetative matter. However, because wood waste materials are not commodity fuels and the supply of wood waste may fluctuate, it is necessary to have the ability to burn limited amounts of fossil fuel in the event that the supply of biomass fuel is not adequate. Therefore, each combustion unit will have the capability to burn biomass, fuel oil, and coal, either alone or in combination.

The cogeneration facility will use low sulfur No. 2 fuel oil only to assist in startup or when the biomass fuel supply is not adequate. The No. 2 distillate fuel oil will have a maximum sulfur content of 0.5 percent and an equivalent maximum SO₂ emission rate of 0.5 lb/MMBtu.

Coal will be utilized only when the biomass fuel supply is not adequate. Coal fired in the facility will be low sulfur coal of approximately 0.7 percent sulfur content, with an equivalent maximum SO₂ emission rate of 1.2 lb/MMBtu.

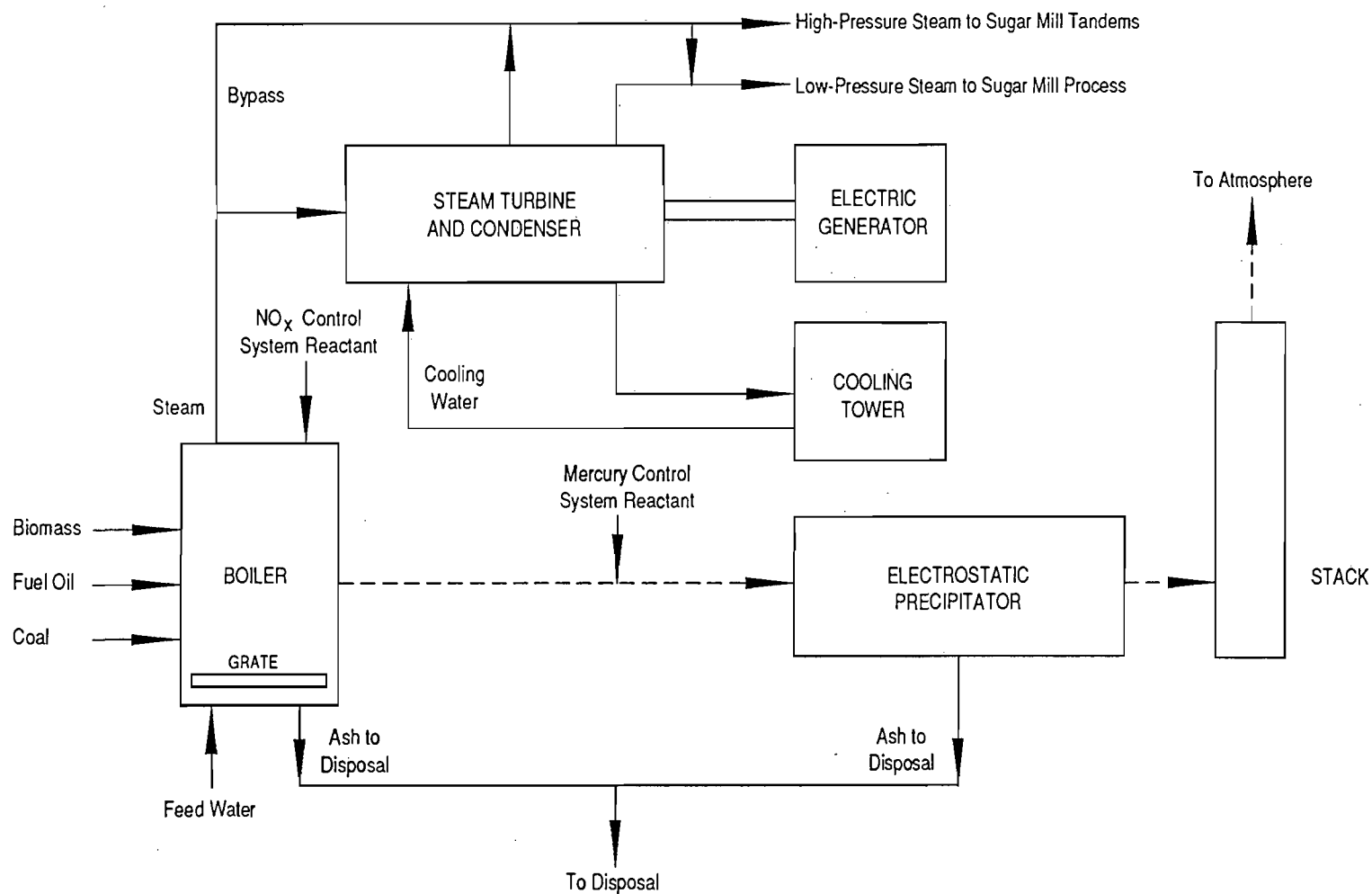


Figure 2-4 SIMPLIFIED FLOW DIAGRAM FOR SOL-ENERGY COGENERATION FACILITY

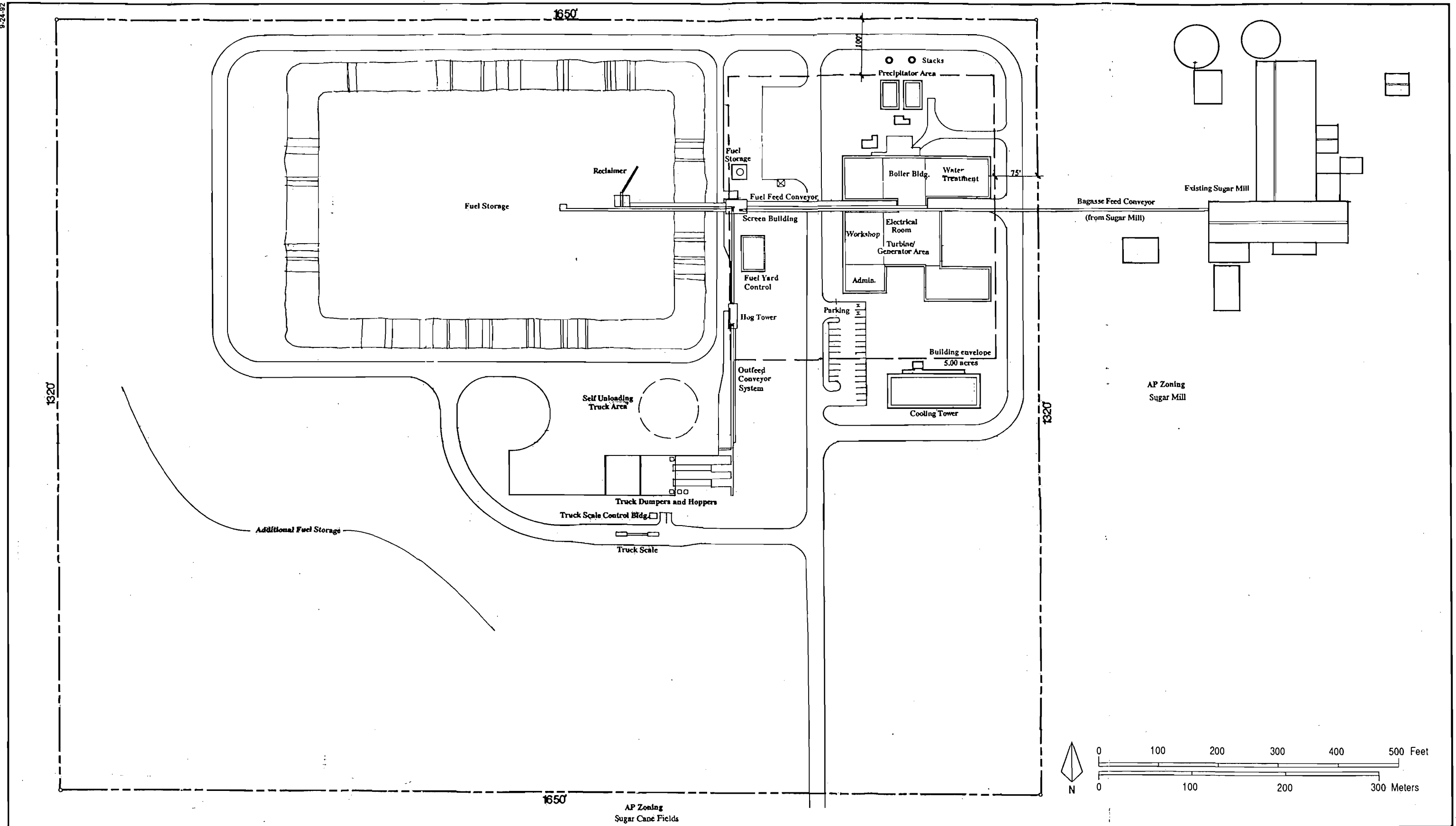


Figure 2-5 CONCEPTUAL PLOT PLAN OF PROPOSED COGENERATION FACILITY

The fuel handling system will be initially designed to handle biomass. The fuel systems are designed to feed reduced rates to the boilers to match boiler demand/use rates. Bagasse fuel can be delivered to the facility and boilers in several ways. Normally, bagasse from the sugar mill will be delivered directly to the boilers by a belt conveyor. Biomass can also be delivered by truck and conveyed to the boilers via the outfeed conveyor system. Biomass can be delivered from either of these sources to the fuel storage area for future reclaim. Biomass fuel from the reclaim system will be deposited on a conveyor and delivered to the boilers.

Biomass will be burned on a traveling or vibrating grate located within each boiler. In this design, biomass material is deposited on the grate, which moves slowly or vibrates, allowing combustion to occur in suspension or on the grate surface. Both underfire and overfire air are supplied to enhance combustion efficiency.

Coal fuel, if utilized, would also be fed to the boilers from the fuel storage area via the reclaim system. The coal will be burned on the grate in the boiler, similar to biomass firing, or by pulverized coal firing.

The proposed boilers will be equipped with fuel oil burners designed to provide maximum combustion efficiency. Associated piping will also be installed.

Fuel specifications for each fuel that may be utilized by the proposed facility are presented in Table 2-1. Based on these fuel specifications, maximum hourly firing rates are shown in Table 2-2 for each fuel when fired alone. The maximum heat input to each boiler due to biomass fuels will be 665 MMBtu/hr. Due to limitations of the boiler and firing system, maximum heat input of fossil fuels will be limited to 460 MMBtu/hr. Biomass and fossil fuels may also be burned in combination, not to exceed a total heat output of approximately 452 MMBtu/hr per boiler.

On an annual basis, all fuels may be fired alone or in combination, not to exceed a total heat output for both boilers of 4.760×10^{12} Btu/yr. In addition, burning of all fossil fuels will be limited to a total of 25 percent of the total annual heat input. Three cases are shown in Table 2-2 to illustrate the anticipated scenario of firing 100 percent biomass fuel and the potential cases of

Table 2-1. Design Fuel Specifications^a for the Sol-Energy Cogeneration Facility

Parameter	Biomass		No. 2 Fuel Oil	Bituminous Coal
	Bagasse	Wood Waste		
Specific Gravity	--	--	0.865	--
Heating Value (Btu/lb)	4,250	5,500	19,175	12,000
Heating Value (Btu/gal)	--	--	138,000	--
Ultimate Analysis (dry basis):				
Carbon	48.93%	49.58%	87.01%	82.96%
Hydrogen	6.14%	5.87%	12.47%	5.41%
Nitrogen	0.25%	0.40%	0.02%	1.58%
Oxygen	43.84%	40.90%	0.00%	5.72%
Sulfur	0.009%	0.009%	0.50%	0.67%
Ash/Inorganic	0.83%	3.24%	0.00%	3.66%
Moisture	52%	37%	--	4.5%

^a Represents average fuel characteristics.Sources: Okeelanta Corp., 1992.
Combustion Engineering, 1981.

Table 2-2. Maximum Fuel Usage and Heat Input Rates, Sol-Energy Cogeneration Facility

Fuel	Heat Input	Heat Transfer Efficiency (%)	Heat Output	Fuel Firing Rate
<u>Maximum Short-Term (per boiler)</u>				
	(MMBtu/hr)		(MMBtu/hr)	
Biomass	665	68	452	156,471 lb/hr ^a
No. 2 Oil	460	85	391	3,333 gal/hr
Coal	460	85	391	38,333 lb/hr
<u>Annual Average (total two boilers)</u>				
	(Btu/yr)		(Btu/yr)	
<u>NORMAL OPERATIONS</u>				
Biomass	7.000E+12	68	4.760E+12	823,529 TPY ^a
No. 2 Oil	0	85	0	0 gal/yr
Coal	0	85	0	0 TPY
	-----		-----	
TOTAL	7.000E+12		4.760E+12	
<u>25% OIL FIRING</u>				
Biomass	4.941E+12	68	3.360E+12	581,294 TPY ^a
No. 2 Oil	1.647E+12	85	1.400E+12	11,934,783 gal/yr
Coal	0	85	0	0 TPY
	-----		-----	
TOTAL	6.588E+12		4.760E+12	
<u>25% COAL FIRING</u>				
Biomass	4.941E+12	68	3.360E+12	581,294 TPY ^a
No. 2 Oil	0	85	0	0 gal/yr
Coal	1.647E+12	85	1.400E+12	68,625 TPY
	-----		-----	
TOTAL	6.588E+12		4.760E+12	

Notes: Total heat output required = 452 MMBtu/hr each boiler and 4.760E+12 Btu/yr total both boilers. Fuels may be burned in combination, not to exceed indicated total heat outputs.

^a Based on heating value for bagasse of 4,250 btu/lb.

firing the maximum amount of fuel oil or the maximum amount of coal, with the remaining heat input due to biomass. When only biomass is fired, the annual heat input requirement is 7.00×10^{12} Btu/yr for the entire facility (total both boilers). Under the worst-case of burning fossil fuels at 25 percent of the total annual heat input, the annual heat input requirement for the entire facility becomes 6.588×10^{12} Btu/yr, due to the different heat transfer efficiency for fossil fuels versus biomass.

Coal handling facilities will be constructed as needed prior to coal-firing. The coal handling system will consist of unloading, transfer, storage, reclaiming, and crushing operations. A railcar unloading system will utilize an enclosed bottom dumping type facility or equivalent. Coal will be delivered to the site via trains consisting of up to 75 railcars or by truck. Each railcar may hold up to 100 tons and each truck up to 25 tons. The cogeneration facility may burn up to approximately 68,625 tons of coal per year under the scenario of 25 percent of total annual heat input from coal.

Ash generated from the combustion process will consist of bottom ash, siftings ash, and fly ash. Bottom ash is ash which falls off the front of the grate onto a submerged conveyor. Siftings ash is ash which drops down through the grate to the bottom of the boiler. Fly ash is ash captured downstream of the boiler in the boiler bank hoppers, air preheater hoppers, and the ESP. Bottom ash generated in the boilers will be handled wet via a submerged drag-chain conveyor. This ash will be delivered to a dumpster for subsequent disposal. The siftings ash collected at the bottom of the boiler and the fly ash collected downstream of the boiler will be conveyed via enclosed drag-chain conveyors to dumpsters. Particulate emissions from the material handling system are discussed in Section 2.4.1.

2.3 APPLICABILITY OF FEDERAL NEW SOURCE PERFORMANCE STANDARDS

Based on the maximum heat input to the cogeneration facility boilers and the type of fuel burned, the boilers will be subject to the federal NSPS for electric utility steam generating units (40 CFR 60, Subpart Da). The Subpart Da standards are summarized in Table 2-3.

Table 2-3. Federal NSPS for Electric Utility Steam-Generating Units Applicable to the Sol-Energy Cogeneration Facility

Pollutant	Emission Limitation
Particulate Matter	Liquid fuel--0.03 lb/10 ⁶ Btu Solid fuel--0.03 lb/10 ⁶ Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide ^a	Resource Recovery Units--1.20 lb/10 ⁶ Btu
Nitrogen Oxides ^a	Fuel Oil--0.30 lb/10 ⁶ Btu Solid fuels: Bituminous coal--0.60 lb/10 ⁶ Btu All other fuels--0.60 lb/10 ⁶ Btu

Note: Emission limits for PM, NO_x, and SO₂ do not apply during periods of startup, shutdown, or malfunction.

^a Compliance determined on a 30-day, rolling average basis.

Source: 40 CFR 60, Subpart Da.

For PM, the NSPS limits emissions to 0.03 lb/MMBtu when burning solid or liquid fuels. An opacity limit also applies, which limits opacity to 20 percent (6-minute average), except up to 27 percent opacity is allowed for one 6-minute period per hour.

In the case of SO₂, the proposed cogeneration units will be classified as "resource recovery units", since combustion of non-fossil fuels will be more than 75 percent on a quarterly (calendar) heat input basis. For such units, the NSPS limits SO₂ emissions to 1.2 lb/MMBtu based on a 30-day rolling average. The proposed facility will comply with the NSPS for SO₂ by burning biomass, low sulfur coal with a maximum sulfur content of approximately 0.7 percent, and very low sulfur distillate fuel oil with a maximum sulfur content of approximately 0.5 percent. Equivalent maximum SO₂ emission rates are 1.2 lb/MMBtu for coal and 0.5 lb/MMBtu for No. 2 fuel oil. Biomass has an inherently low sulfur content (i.e., average of about 0.009 percent by weight).

The NSPS for NO_x is 0.30 lb/MMBtu heat input for fuel oil firing and 0.60 lb/MMBtu for solid fuels, including bagasse, wood and coal. The proposed maximum NO_x emission rate for the facility for each fuel is lower than the NSPS. Compliance with the NO_x emissions limitation under Subpart Da is based on a 30-day rolling average.

Further requirements under 40 CFR 60 Subpart Da include emission monitoring. Continuous monitoring is required for opacity, NO_x, and carbon dioxide or oxygen. Continuous monitoring is defined as "a minimum of 18 hours in at least 22 out of 30 successive boiler operating days" (40 CFR 60.47a (f)). Specifically, a continuous opacity monitor must be installed at a point free of interference from water to monitor PM emissions. NO_x emissions must also be measured at the stack. Further, at the point NO_x emissions are monitored, oxygen or carbon dioxide must be monitored. The continuous monitoring systems are to be operated and data recorded during "all periods of operation including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks and span adjustments" [40 CFR 60.47a (e)].

2.4 EMISSIONS OF REGULATED POLLUTANTS

2.4.1 COGENERATION FACILITY BOILERS

The proposed emission limits for all regulated pollutants emitted by the proposed boilers are presented in Table 2-4. Maximum emissions of total suspended particulate matter PM(TSP) and particulate matter less than 10 microns in diameter (PM10) are based upon an electrostatic precipitator (ESP) control device to meet New Source Performance Standards (NSPS) for electric utility steam generating units, as specified in 40 CFR 60 Subpart Da.

The maximum NO_x emissions reflect a flue-gas NO_x control system (i.e., selective non-catalytic reduction system) which will be designed to achieve at least a 40 percent NO_x reduction efficiency. The proposed emission rates are 0.12 lb/MMBtu for biomass fuels and No. 2 fuel oil, and 0.17 lb/MMBtu for coal firing, all based on a 30-day rolling average. Carbon monoxide (CO) and volatile organic compounds (VOCs) emissions reflect the proposed boiler design and good combustion practices.

Emissions of SO₂ are based on the maximum sulfur content of the fuels, subsequent SO₂ emissions, and the fuel firing rates. NSPS limits SO₂ emissions due to fossil fuel firing to 1.2 lb/MMBtu or less, based on a 30-day rolling average. Compliance with this limit will be achieved by burning biomass fuels, low sulfur (approximately 0.7 percent maximum) coal, and very low sulfur (approximately 0.5 percent maximum) fuel oil. Biomass fuels are inherently low in sulfur, resulting in low emission rates. Both annual average and 24-hour limits are proposed for SO₂ (see Table 2-4).

Emissions of other regulated pollutants, including trace elements, for biomass are based on sugar industry test data, emission tests of wood-fired boilers at Seminole Kraft Corporation in 1990, fuel sampling, and EPA Publication AP-42 (EPA, 1988). Further, for No.2 fuel oil and coal, emission factors for trace elements were obtained from Toxic Air Emission Factors: A Compilation, revised edition (EPA, 1988a) and Estimating Air Toxic Emissions from Coal and Oil Combustion Sources (EPA, 1989).

Mercury emissions from the proposed boilers are based upon the best available data concerning emissions from firing bagasse and wood. No bagasse boiler mercury test data is available.

Table 2-4. Proposed Emission Limits for the Sol-Energy Facility

Pollutant	Emission Limit (lb/MMBtu)		
	Biomass	No.2 Oil	Bit. Coal
Particulate (TSP)	0.03	0.03	0.03
Particulate (PM10)	0.03	0.03	0.03
Sulfur Dioxide			
24-hour average	0.10	0.5	1.2
Annual average ^a	0.02	0.5	1.2
Nitrogen Oxides			
Annual average ^a	0.12	0.12	0.17
Carbon Monoxide			
8-hour average	0.35 ✓	0.2	0.2
Volatile Organic Compounds	0.06	0.03	0.03
Lead	2.5E-05	8.9E-07	6.4E-05
Mercury	^b	2.4E-06	8.4E-06
Beryllium	--	3.5E-07	5.9E-06
Fluorides	--	6.3E-06	0.024
Sulfuric Acid Mist	0.003	0.015	0.036

^a Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.^b Limits are 5.5×10^{-6} lb/MM Btu for bagasse and 0.29×10^{-6} lb/MM Btu for wood waste materials.

However, sugar cane dead leaves have been tested (Patrick, 1991). The dead leaves are considered to be similar to bagasse, which is dead sugar cane stalk. Numerous samples of the dead sugar cane leaves yielded an average mercury content of 0.068 ppm (dry basis). This equates to an uncontrolled mercury emission factor of 6.6×10^{-5} lb/ton of wet bagasse, or 7.8×10^{-6} lb/MMBtu. Published test data from wood-fired spreader stoker boilers indicate that uncontrolled mercury emissions for wood waste firing are 0.41×10^{-6} lb/MMBtu (see Appendix A).

Published information on the mercury content of No. 2 fuel oil allowed derivation of an emission factor for this fuel. A recent report (KBN, 1992) presented mercury emission factors for coal-fired boilers and formed the basis for mercury emissions from coal-firing.

The mercury emission factors also reflect a minimum 30 percent control efficiency resulting from a mercury control system (carbon injection or equivalent) and an ESP control device. However, due to the uncertainty related to the emission estimates (i.e., limited data on bagasse and wood waste materials as well as mercury control systems), a 30 percent control efficiency may not be necessary to achieve the proposed emission rates. It is therefore requested that only the emission limitations for mercury (i.e., lb/MMBtu and TPY limits) become permit conditions. A percent removal efficiency for mercury should not be specified as a permit condition.

Sulfuric acid mist emissions are based upon EPA AP-42 (EPA, 1988), which indicates sulfuric acid mist is approximately 3 percent of sulfur dioxide emissions.

Maximum hourly emissions from each of three proposed boilers for each fuel are presented in Table 2-5. Each emission factor is noted with its specific reference. As shown, the maximum hourly emissions occur when burning either biomass or bituminous coal.

The total maximum annual emissions for each pollutant from all three boilers are presented in Table 2-6. These are based upon the same emission factors as described previously. The total maximum emissions for each pollutant is based upon the worst-case fuel operating scenario and is indicated in the far right column of Table 2-6. Derivations and sample calculations for the emission factors are presented in Appendix A.

Table 2-5. Maximum Short-Term Emissions for Sol-Energy Cogeneration Facility (per boiler)

Regulated Pollutant	Biomass				#2 Oil				Coal				Maximum Emissions for any fuel (lb/hr)
	Emission Factor	Ref.	Activity Factor	Maximum Emissions	Emission Factor	Ref.	Activity Factor	Maximum Emissions	Emission Factor	Ref.	Activity Factor	Maximum Emissions	
	(lb/MMBtu)		(MMBtu/hr)		(lb/hr)		(lb/MMBtu)		(MMBtu/hr)		(lb/hr)		
Particulate (TSP)	0.03	1	665	20.0	0.03	1	460	13.8	0.03	1	460	13.8	20.0
Particulate (PM10)	0.03	1	665	20.0	0.03	1	460	13.8	0.03	1	460	13.8	20.0
Sulfur dioxide	0.10 ^a	2	665	66.5 ^a	0.5	9	460	230.0 ^a	1.2	1	460	552.0 ^a	552.0 ^a
Nitrogen oxides	0.12 ^b	3	665	79.8 ^b	0.12 ^b	3	460	55.2 ^b	0.17 ^b	3	460	78.2 ^b	79.8 ^b
Carbon monoxide	0.35 ^c	4	665	232.8 ^c	0.2 ^c	4	460	92.0 ^c	0.2 ^c	4	460	92.0 ^c	232.8 ^c
VOC	0.06	4	665	39.9	0.03	4	460	13.8	0.03	4	460	13.8	39.9
Lead	2.5E-05	5	665	0.017	8.9E-07	10	460	0.0004	6.4E-05	12	460	0.029	0.029
Mercury	5.5E-06	6	665	0.0037	2.4E-06	11	460	0.0011	8.4E-06	13	460	0.0039	0.0039
Beryllium	—	7	—	—	3.5E-07	12	460	0.00016	5.9E-06	12	460	0.0027	0.0027
Fluorides	—	—	—	—	6.3E-06	14	460	0.003	0.024	14	460	11.0	11.0
Sulfuric acid mist	0.003	8	665	2.00	0.015	8	460	6.9	0.036	8	460	16.6	16.6
Total reduced sulfur	—	—	—	—	—	—	—	—	—	—	—	—	—
Asbestos	—	—	—	—	—	—	—	—	—	—	—	—	—
Vinyl Chloride	—	—	—	—	—	—	—	—	—	—	—	—	—

^a 24-hour average.^b 30-day rolling average.^c 8-hour average.

References:

1. Emission Factor based on NSPS 40CFR 60 Subpart Da.
2. Based upon maximum sulfur content of bagasse of 0.1 percent, dry basis (0.048 percent, wet basis).
3. Based on NO_x control system.
4. Based on boiler design.
5. No data available for bagasse; based on testing on wood fired boilers in California (Sassenrath, 1991).
6. Based on mercury content in sugar cane and mercury control system.
7. Emission Tests for Seminole Kraft (1990) and TAPPI Proceedings (1991).
8. Based on AP-42; 3% of SO₂ emissions.
9. Based on maximum sulfur content of No. 2 fuel oil.
10. Toxic Air Emission Factors EPA 1988 (EPA-450/2-88-006a).
11. Toxic Air Emission Factors EPA 1988 (EPA-450/2-88-006a), using 30% removal from mercury control system.
12. Estimating Air Toxic Emissions from Coal and Oil Combustion Sources (EPA -450/2-89-001) (1989).
13. Based on "Mercury Emissions to the Atmosphere in Florida" (KBN, 1992), and 30% removal from mercury and ESP control system.
14. Based on "Emissions Assessment of Conventional Stationary Combustion Sources: Volume V: Industrial Combustion Sources (EPA-600/7-81-003c).

Table 2-6. Maximum Annual Emissions for Sol-Energy Cogeneration Facility (total all boilers)

Regulated Pollutant	Biomass			No. 2 Fuel			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Normal Operations										
Particulate (TSP)	0.03	7.000	105.00	--	--	--	--	--	--	105.00 ^a
Particulate (PM10)	0.03	7.000	105.00	--	--	--	--	--	--	105.00 ^a
Sulfur dioxide	0.02	7.000	70.0	--	--	--	--	--	--	70.0
Nitrogen oxides	0.12	7.000	420.0	--	--	--	--	--	--	420.0
Carbon monoxide	0.35	7.000	1,225.00	--	--	--	--	--	--	1,225.00 ^a
VOC	0.06	7.000	210.00	--	--	--	--	--	--	210.00 ^a
Lead	2.5E-05 ^b	7.000	0.09	--	--	--	--	--	--	0.09
Mercury	^b	7.000	^b	--	--	--	--	--	--	0.0139
Beryllium	--	--	--	--	--	--	--	--	--	--
Fluorides	--	--	--	--	--	--	--	--	--	--
Sulfuric acid mist	0.0006	7.000	2.10	--	--	--	--	--	--	2.10
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
25% Oil Firing										
Particulate (TSP)	0.03	4.941	74.12	0.03	1.647	24.71	--	--	--	98.82
Particulate (PM10)	0.03	4.941	74.12	0.03	1.647	24.71	--	--	--	98.82
Sulfur dioxide	0.02	4.941	49.41	0.5	1.647	411.75	--	--	--	461.16
Nitrogen oxides	0.12	4.941	296.5	0.12	1.647	98.8	--	--	--	395.3
Carbon monoxide	0.35	4.941	864.68	0.2	1.647	164.70	--	--	--	1,029.38
VOC	0.06	4.941	148.23	0.03	1.647	24.71	--	--	--	172.94
Lead	2.5E-05 ^b	4.941	0.06 ^b	8.9E-07 ^b	1.647	0.001 ^b	--	--	--	0.06
Mercury	--	4.941	--	--	1.647	--	--	--	--	0.0139
Beryllium	--	--	--	3.5E-07	1.647	0.0003	--	--	--	0.0003
Fluorides	--	--	--	6.3E-06	1.647	0.0052	--	--	--	0.005
Sulfuric acid mist	0.0006	4.941	1.48	0.015	1.647	12.35	--	--	--	13.83
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--
Vinyl Chloride	--	--	--	--	--	--	--	--	--	--
25% Coal Firing										
Particulate (TSP)	0.03	4.941	74.12	--	--	--	0.03	1.647	24.71	98.82
Particulate (PM10)	0.03	4.941	74.12	--	--	--	0.03	1.647	24.71	98.82
Sulfur dioxide	0.02	4.941	49.41	--	--	--	1.2	1.647	988.20	1,071.46 ^a
Nitrogen oxides	0.12	4.941	296.5	--	--	--	0.17	1.647	140.00	436.5 ^a
Carbon monoxide	0.35	4.941	864.68	--	--	--	0.2	1.647	164.70	1,029.38
VOC	0.06	4.941	148.23	--	--	--	0.03	1.647	24.71	172.94
Lead	2.5E-05 ^b	4.941	0.06 ^b	--	--	--	6.4E-05 ^b	1.647	0.05 ^b	0.11 ^a
Mercury	--	4.941	--	--	--	--	--	1.647	--	0.0139 ^a
Beryllium	--	--	--	--	--	--	5.9E-06	1.647	0.0049	0.0049 ^a
Fluorides	--	--	--	--	--	--	0.024	1.647	19.76	19.76 ^a
Sulfuric acid mist	0.0006	4.941	1.48	--	--	--	0.036	1.647	29.65	31.13 ^a
Total reduced sulfur	--	--	--	--	--	--	--	--	--	--
Asbestos	--	--	--	--	--	--	--	--	--	--

^a Denotes maximum annual emissions for any fuel scenario.^b Refer to text for explanation.

The annual SO₂ emissions presented in Table 2-6 include the worst-case scenario of 25 percent coal burning in any one year, with remaining heat input from biomass. However, according to the zoning approval with the Palm Beach County Planning and Zoning Board, annual SO₂ emissions must be limited to a total of 1,000 TPY for both the Sol-Energy and Flo-Energy (i.e., Osceola and Okeelanta) cogeneration facilities combined, averaged over the life of the project (estimated at 30 years). Therefore, if fossil fuels are burned in either facility and they result in annual SO₂ emissions greater than 1,000 tons, the use of fossil fuels must be limited in other years to produce average annual SO₂ emissions of less than 1,000 tons for both facilities combined. A copy of the zoning requirements is contained in Appendix C.

In the case of mercury emissions, the Palm Beach County zoning approval requires that maximum annual mercury emissions for the cogeneration facility cannot exceed current annual mercury emissions. As presented in Appendix B, the best available estimate of current mercury emissions from the Osceola Farms facility, based on limited data, is 0.0137 TPY, based on a 2-year average, or 0.0139 based upon the highest year out of the last 2 years. As a result, the proposed mercury limit for the cogeneration facility is 0.0139 TPY. It is noted that Osceola Farms may conduct testing in the future to better establish baseline emission factors and emission levels for mercury.

In order to meet the proposed mercury emission limit (in TPY) under certain fuel firing scenarios, the annual firing of bagasse and/or coal may need to be limited due to the higher emission factors for bagasse and coal compared to wood waste firing. The limits on firing of different fuels will depend upon the mix of fuels, actual emission factors, and the total heat input in any given year. Once operation of the facility commences, a test program will be undertaken by Sol-Energy to establish actual emission factors for each fuel. Based on the established emission factors, a fuel management plan will be implemented to insure the 0.0139 TPY mercury emission limit (or the applicable limit based on test data) is not exceeded. The fuel management plan will be submitted to FDER's West Palm Beach office and to the Palm Beach County Health Unit for review.

It is emphasized that the baseline mercury calculations are based on very limited data, and further testing may indicate different emission factors. Therefore, these figures are subject to change as

better information becomes available. It is therefore requested, as stated previously, that only the emission limits for mercury in terms of lb/MMBtu and TPY become permit conditions.

2.4.2 FUGITIVE EMISSIONS OF PARTICULATE MATTER

Sources of fugitive particulate emissions were identified based on the descriptions of the coal and material handling and storage processes. Emissions of fugitive dust can occur from four types of coal handling operations: batch drop, coal crushing, wind erosion, and vehicular traffic.

Presented in Table 2-7 is an inventory and annual average emission factors for each of the four processes. Computations are based upon EPA AP-42 (EPA, 1988) Sections 11.2.1 and 11.2.3. The emission factors for batch drop are a function of moisture content and wind speed. Moisture content is based upon the average analysis of bituminous coal of 4.5 percent moisture (refer to Table 2-1 and AP-42). Fly ash is assumed to have a low moisture content, i.e., 2.0 percent. From published weather data, the annual average wind speed at West Palm Beach is 9.4 mph.

For railcar unloading, which will be performed in an enclosed structure, 70 percent control for enclosure is indicated, based on published literature (ERT, 1981). The reclaim hopper, being underground, will be essentially enclosed, resulting in a 90 percent control efficiency (ERT, 1981). The uncontrolled emission factor for coal crushing was determined directly from AP-42 for high moisture ore: 0.02 lb/ton for PM(TSP) and 0.009 lb/ton for PM10. Published data indicate 70 percent control provided by enclosure of the coal crusher (ERT, 1981).

Vehicular traffic emissions were determined based on silt content of the road material, vehicle speed and weight, wheel count and wet days (i.e., precipitation more than 0.01 inch) per year. For the coal pile maintenance, one vehicle operating 8 hours a day for 365 days per year will be sufficient to maintain the pile. A control efficiency of 50 percent was applied due to watering the coal pile during dry or dusty conditions, based on published information concerning fugitive dust emission controls for coal storage piles (ERT, 1981).

A wind erosion emission factor determination is outlined in AP-42 Section 11.2.7. A computer program developed by EPA contract (Midwest Research Institute, 1990) was used to apply the AP-42 equations to the proposed coal storage pile. A summary of variables used is presented along with the wind erosion emission factors in Appendix A. A circular, conical coal pile of

Table 2-7. Sol-Energy Cogeneration Facility Annual Average Uncontrolled Fugitive Emission Factors

Source	Type of Operation ^a	M Moisture Content (%)	U Wind Speed (mph)	E Emission Factor (lb/ton)
Railcar Unloading	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Coal Pile	Batch Drop	4.5	9.4	0.00234
Reclaim Hopper	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Crusher	Batch Drop	4.5	9.4	0.00234
Coal Crusher	Coal Crushing	-	-	0.02 ^b
Crusher-to-Conveyor	Batch Drop	4.5	9.4	0.00234
Conveyor-to-Boiler Silo	Batch Drop	4.5	9.4	0.00234
Storage Pile	Wind Erosion	-	-	^c
Coal Pile Maintenance	Vehicular Traffic	-	-	0.90328 ^d
Fly Ash Transfer	Batch Drop	2.0	9.4	0.00727

^a Batch drop emission factors are computed from AP-42 (EPA, 1988) Section 11.2.3:

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

^b Emission factor for coal crusher taken from AP-42, Table 8.23-1, for high-moisture ore.

^c Emission calculations provided in Appendix A.

^d lb/vehicle mile traveled per day, based on AP-42 Section 11.2.1 (EPA, 1988).

500 ft diameter and 30 ft height was assumed, which is more than large enough to accommodate a full year's supply of coal for the facility (i.e., 68,625 TPY at 25 percent of total facility heat input). Moisture content used was 4.5 percent (as described above), and average silt content used was 2.2 percent based on publication AP-42. It was further assumed that the coal pile would be disturbed once every four days, based on using coal only 25 percent of the time during a year. In addition, it is assumed that 50 percent of the coal pile would be disturbed for each disturbance day. The resulting PM₁₀ emissions are calculated as 95,653 g/yr, or 0.105 TPY. Corresponding PM(TSP) emissions are double this, or 0.211 TPY. Output from the computer program is provided in Appendix A.

The fly ash handling system will utilize enclosed conveyors and transfer points. However, fly ash handling will potentially generate fugitive PM emissions at the point of discharge into the dumpsters. Estimated annual emissions are based on the maximum amount of fly ash potentially generated (i.e., when 100 percent biomass is burned).

Annual average fugitive PM emissions are presented in Table 2-8. The emissions are based on the maximum annual coal throughput of 68,625 TPY. Total annual PM(TSP) fugitive emissions are 4.162 TPY, and PM₁₀ emissions are 1.509 TPY.

The mercury control system employed on the cogeneration boilers may utilize a solid sorbent material, such as carbon. If utilized, the solid material will be delivered to the site by truck and pneumatically conveyed to a storage silo for each boiler. The silos will be controlled by use of a bin vent filter or baghouse to reduce fugitive PM emissions to 0.01 gr/acf or less. Estimated parameters for the control devices are presented in Table 2-9.

The estimated annual PM(TSP) emissions from fugitive sources and silos total 4.332 TPY for the proposed facility. Total annual PM(10) emissions are estimated at 1.679 TPY.

2.5 EMISSIONS OF NON-REGULATED POLLUTANTS

Emission factors for non-regulated pollutants were obtained from EPA's compilation of toxic air pollutant emission factors (EPA, 1988) and the EPA VOC and PM speciation database. Emission factors are available from these references for fuel-oil, coal, and wood combustion. Bagasse

Table 2-8. Sol-Energy Cogeneration Facility Maximum Annual PM Emission Rates for Fugitive Dust Sources

Source	Uncontrolled Emission Factor (lb/ton)	Control	Control Efficiency (%)	Controlled Emission Factor (lb/ton)	Maximum Annual Thruput (tons/yr)	Maximum Annual PM(TSP) Emissions (tons/yr)	PM10 Size Mult.	Maximum Annual PM10 Emissions (tons/yr)
Railcar Unloading	0.00234	Enclosure	70	0.00070	68,625	0.024	0.35	0.008
Conveyor-to-Coal Pile	0.00234	None	0	0.00234	68,625	0.080	0.35	0.028
Reclaim Hopper	0.00234	Enclosure	90	0.00023	68,625	0.008	0.35	0.003
Conveyor-to-Crusher	0.00234	None	0	0.00234	68,625	0.080	0.35	0.028
Coal Crusher	0.02	Enclosure	70	0.006	68,625	0.206	0.45	0.093
Crusher-to-Conveyor	0.00234	None	0	0.00234	68,625	0.080	0.35	0.028
Conveyor-to-Boiler Silo	0.00234	None	0	0.00234	68,625	0.080	0.35	0.028
Storage Pile Wind Erosion	—	None	0	—	—	0.211 ^a	0.5	0.105 ^a
Coal Pile Maintenance ^a	0.90328	Watering	50	0.45164 ^b	14,600 ^c	3.297	0.35	1.154
Fly Ash Transfer	0.00727	None	0	0.00727	26,353 ^d	0.096	0.35	0.034
TOTAL						4.162		1.509

^a Refer to Appendix A and text for derivation.

^b lb/VMT.

^c Vehicle miles traveled per year.

^d 823,529 TPY biomass @ 3.20 percent ash; assumes all ash is fly ash.

Table 2-9. Parameters for Mercury Control System--Silo Baghouses

Emission Point	Air Flow Rate (acfm)	Particulate Emissions		Operating Hours (hr/yr)	PM(TSP)/PM10 Emissions (TPY)
		(gr/acf)	(lb/hr)		
Mercury Removal Agent Silo 1	2,000	0.01	0.17	1,000	0.085
Mercury Removal Agent Silo 2	2,000	0.01	0.17	1,000	0.085

Note: acfm = actual cubic feet per minute.

gr/acf = grains per actual cubic foot.

hr/yr = hours per year.

lb/hr = pounds per hour.

TPY = tons per year.

emission factors are not available. However, emissions due to bagasse firing are expected to be similar to those from wood-waste burning. Stack test results from a wood fired boiler at Seminole Kraft Corporation in Jacksonville, Florida, conducted in 1990, provided biomass emission factors for most of the non-regulated pollutants listed. The emission factors and resulting emission rates are very low.

The estimated non-regulated pollutant emissions also account for the possibility that small amounts of treated wood may be present in the wood-waste stream. Sol-Energy will not knowingly accept treated wood. Nonetheless, the estimated emissions for arsenic, chromium, and copper are based on 3 percent treated wood in the wood-waste stream. Calculations are presented in Appendix A.

Residual ammonia emissions are associated with use of a selective non-catalytic reduction (SNCR) system for NO_x emission control. Testing at three municipal solid waste combustors located in California and equipped with SNCR systems displayed ammonia slip emissions ranging from 2 to 35 ppm, with an average of about 10 ppm. For the Sol-Energy facility, a maximum of 20 ppm NH_3 slip is considered achievable when burning biomass, and this results in maximum NH_3 emissions of 10.0 lb/hr per boiler when burning biomass fuels. This is equivalent to 0.015 lb/MMBtu heat input. For oil and coal burning, a higher ammonia slip is proposed due to the higher ammonia injection rate required to achieve the proposed NO_x emission limit. An ammonia slip of 65 ppm is considered achievable, which results in ammonia emissions of 22.1 lb/hr per boiler. This is equivalent to 0.048 lb/MMBtu heat input.

Maximum hourly emissions of non-regulated pollutants are presented in Table 2-10. Estimates of maximum annual emissions of non-regulated pollutants are presented in Table 2-11. The emission factors are based upon the sources listed in Table 2-10. Each emission factor is footnoted with its specific reference. Derivations and sample calculations for these emission factors are presented in Appendix A.

Table 2-10. Maximum Hourly Emissions of Non-Regulated Pollutants for Sol-Energy Cogeneration Facility (per boiler)

Non Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Maximum Hourly Emission any fuel (lb/hr)			
	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)	Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)	Emission Factor (lb/MMBtu)		Ref	Activity Factor (MMBtu/hr)	Hourly Emissions (lb/hr)
Ammonia	1.5E-02	8	665	10.0	4.8E-02	8	460	22.1	4.8E-02	8	460	22.1	22.1
Antimony	UD	3	665	—	2.32E-06	5	460	0.0011	3.49E-05	5	460	0.016	0.016
Arsenic	1.62E-04	10	665	0.11	5.00E-07	1	460	0.0002	2.64E-05	4	460	0.012	0.11
Barium	1.06E-04	3	665	0.07	6.69E-06	5	460	0.0031	7.44E-04	5	460	0.34	0.34
Bromine	1.47E-03	7	665	0.98	6.97E-06	5	460	0.00321	7.90E-04	5	460	0.363	0.98
Cadmium	5.43E-06	2	665	0.0036	1.58E-06	1	460	0.0007	1.36E-06	4	460	0.001	0.0036
Chromium	1.54E-04	10	665	0.10	1.39E-05	1	460	0.0064	1.66E-05	4	460	0.008	0.10
Chromium + 6	3.81E-05	9	665	0.025	2.78E-06	9	460	0.0013	3.32E-06	9	460	0.002	0.025
Cobalt	4.98E-04	7	665	0.33	1.17E-05	5	460	0.0054	7.20E-05	5	460	0.033	0.33
Copper	1.45E-05	10	665	0.0096	4.20E-05	1	460	0.019	1.71E-04	4	460	0.079	0.079
Dioxin	7.18E-12	2	665	4.8E-09	—	—	460	—	—	—	460	—	4.8E-09
Furan	3.75E-10	2	665	2.5E-07	—	—	460	—	—	—	460	—	2.5E-07
Formaldehyde	6.77E-04	2	665	0.45	4.05E-04	1	460	0.19	2.20E-04	4	460	0.101	0.45
Hydrogen Chloride	3.70E-02	3	665	24.6	6.37E-04	6	460	0.293	7.90E-02	6	460	36.3	36.3
Indium	1.27E-04	7	665	0.084	—	—	460	—	—	—	460	—	0.084
Manganese	7.98E-04	2	665	0.53	3.08E-06	1	460	0.0014	3.10E-05	4	460	0.014	0.53
Molybdenum	2.54E-04	7	665	0.17	4.88E-06	5	460	0.0022	8.83E-05	5	460	0.041	0.17
Nickel	4.41E-05	2	665	0.029	4.76E-05	1	460	0.022	1.02E-03	4	460	0.47	0.47
Phosphorus	3.53E-04	3	665	0.23	5.81E-06	5	460	0.0027	8.60E-04	5	460	0.40	0.40
Selenium	UD	3	665	—	4.60E-06	1	460	0.0021	5.34E-05	5	460	0.025	0.025
Silver	2.94E-05	3	665	0.020	—	—	460	—	—	460	—	0.017	0.020
Thallium	UD	3	665	—	—	—	460	—	—	460	—	—	—
Tin	1.62E-04	7	665	0.11	3.30E-05	5	460	0.015	8.83E-05	5	460	0.041	0.11
Zinc	4.24E-04	2	665	0.28	6.69E-06	5	460	0.0031	3.49E-04	5	460	0.16	0.28
Zirconium	9.29E-05	7	665	0.062	—	—	460	—	—	—	460	—	0.062

Note: UD = undetectable levels in gas stream.

* Denotes maximum for any fuel scenario.

References

- 1: Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources, Second Edition EPA-450/2-90-011 (1990).
- 2: Based on "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath, 1991 TAPPI Proceedings.
- 3: Based on stack test results of wood fired boilers and fuel analysis at Seminole Kraft Corporation (1990) equipped with wet scrubbers.
- 4: Estimating Emissions from Oil and Coal Combustion Sources EPA-450/2-89-001 (1989).
- 5: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design and then assuming 90% control from ESP.
- 6: Emissions Assessment of Conventional Stationary Combustion Systems Volume V, 1981. Based on an uncontrolled spreader stoker design.
- 7: EPA PM/VOC Speciation Database, updated October, 1989.
- 8: Based on maximum 20 ppm NH₃ in exhaust gases; see text.
- 9: Based upon stack test data at Dade County RRF, 1992, which indicated less than 20% of total chromium was chromium⁺⁶.
- 10: Same as reference 2; includes 3% treated wood burning.

Source: KBN, 1992.

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for Sol-Energy Cogeneration Facility (total all boilers) (Page 1 of 2)

Non Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Normal Operations										
Ammonia	1.5E-02	7.000	52.5	--	--	--	--	--	--	52.5
Antimony	UD	7.000	--	--	--	--	--	--	--	--
Arsenic	5.58E-05	7.000	0.20	--	--	--	--	--	--	0.20 ^a
Barium	1.06E-04	7.000	0.37	--	--	--	--	--	--	0.37
Bromine	1.47E-03	7.000	5.15	--	--	--	--	--	--	5.1 ^a
Cadmium	5.43E-06	7.000	0.019	--	--	--	--	--	--	0.019 ^a
Chromium	5.54E-05	7.000	0.194	--	--	--	--	--	--	0.194 ^a
Chromium +6	1.35E-05	7.000	0.047	--	--	--	--	--	--	0.047 ^a
Cobalt	4.98E-04	7.000	1.74	--	--	--	--	--	--	1.74 ^a
Copper	7.23E-05	7.000	0.25	--	--	--	--	--	--	0.25
Dioxin	7.18E-12	7.000	2.5E-08	--	--	--	--	--	--	2.5E-08 ^a
Furan	3.75E-10	7.000	1.3E-06	--	--	--	--	--	--	1.3E-06 ^a
Formaldehyde	6.77E-04	7.000	2.37	--	--	--	--	--	--	2.37 ^a
Hydrogen Chloride	3.70E-02	7.000	129.50	--	--	--	--	--	--	129.5
Indium	1.27E-04	7.000	0.44	--	--	--	--	--	--	0.44 ^a
Manganese	7.98E-04	7.000	2.79	--	--	--	--	--	--	2.8 ^a
Molybdenum	2.54E-04	7.000	0.89	--	--	--	--	--	--	0.89 ^a
Nickel	4.41E-05	7.000	0.15	--	--	--	--	--	--	0.15
Phosphorus	3.53E-04	7.000	1.24	--	--	--	--	--	--	1.24
Selenium	UD	7.000	--	--	--	--	--	--	--	--
Silver	2.94E-05	7.000	0.103	--	--	--	--	--	--	0.103 ^a
Thallium	UD	7.000	--	--	--	--	--	--	--	--
Tin	1.62E-04	7.000	0.57	--	--	--	--	--	--	0.57 ^a
Zinc	4.24E-04	7.000	1.48	--	--	--	--	--	--	1.48 ^a
Zirconium	9.29E-05	7.000	0.33	--	--	--	--	--	--	0.33 ^a
25% Oil Firing										
Ammonia	1.5E-02	4.941	37.1	4.8E-02	1.647	39.5	--	--	--	76.6 ^a
Antimony	UD	4.941	--	2.32E-06	1.647	0.0019	--	--	--	0.0019
Arsenic	5.58E-05	4.941	0.138	5.00E-07	1.647	0.0004	--	--	--	0.138
Barium	1.06E-04	4.941	0.26	6.69E-06	1.647	0.0055	--	--	--	0.27
Bromine	1.47E-03	4.941	3.632	6.97E-06	1.647	0.0057	--	--	--	3.637
Cadmium	5.43E-06	4.941	0.013	1.58E-06	1.647	0.0013	--	--	--	0.015
Chromium	5.54E-05	4.941	0.137	1.39E-05	1.647	0.0115	--	--	--	0.149
Chromium +6	1.35E-05	4.941	0.033	2.78E-06	1.647	0.0023	--	--	--	0.035
Cobalt	4.98E-04	4.941	1.23	1.17E-05	1.647	0.0097	--	--	--	1.24
Copper	7.23E-05	4.941	0.18	4.20E-05	1.647	0.0346	--	--	--	0.21
Dioxin	7.18E-12	4.941	1.8E-08	--	1.647	--	--	--	--	1.8E-08
Furan	3.75E-10	4.941	9.3E-07	--	1.647	--	--	--	--	9.3E-07
Formaldehyde	6.77E-04	4.941	1.67	4.05E-04	1.647	0.33	--	--	--	2.00
Hydrogen Chloride	3.70E-02	4.941	91.41	6.37E-04	1.647	0.5244	--	--	--	91.93
Indium	1.27E-04	4.941	0.31	--	1.647	--	--	--	--	0.31
Manganese	7.98E-04	4.941	1.97	3.08E-06	1.647	0.0025	--	--	--	2.0
Molybdenum	2.54E-04	4.941	0.63	4.88E-06	1.647	0.0040	--	--	--	0.63
Nickel	4.41E-05	4.941	0.11	4.76E-05	1.647	0.0392	--	--	--	0.15
Phosphorus	3.53E-04	4.941	0.87	5.81E-06	1.647	0.0048	--	--	--	0.88

Table 2-11. Maximum Annual Emissions of Non-Regulated Pollutants for Sol-Energy Cogeneration Facility (total all boilers) (Page 2 of 2)

Non Regulated Pollutant	Biomass			No. 2 Fuel Oil			Coal			Total Annual Emissions (TPY)
	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	Emission Factor (lb/MMBtu)	Activity Factor (E12 Btu/yr)	Annual Emissions (TPY)	
Selenium	UD	4.941	--	4.60E-06	1.647	0.0038	--	--	--	0.0038
Silver	2.94E-05	4.941	0.073	--	1.647	--	--	--	--	0.073
Thallium	UD	4.941	--	--	1.647	--	--	--	--	--
Tin	1.62E-04	4.941	0.40	3.30E-05	1.647	0.027	--	--	--	0.43
Zinc	4.24E-04	4.941	1.05	6.69E-06	1.647	0.0055	--	--	--	1.1
Zirconium	9.29E-05	4.941	0.23	--	1.647	--	--	--	--	0.23
25% Coal Firing										
Ammonia	1.5E-02	4.941	37.1	--	--	--	4.8E-02	1.647	39.5	76.6 ^a
Antimony	UD	4.941	--	--	--	--	3.49E-05	1.647	0.029	0.029 ^a
Arsenic	5.58E-05	4.941	0.138	--	--	--	2.64E-05	1.647	0.022	0.16
Barium	1.06E-04	4.941	0.26	--	--	--	7.44E-04	1.647	0.61	0.87 ^a
Bromine	1.47E-03	4.941	3.63	--	--	--	7.90E-04	1.647	0.651	4.28
Cadmium	5.43E-06	4.941	0.013	--	--	--	1.36E-06	1.647	0.0011	0.015
Chromium	5.54E-05	4.941	0.137	--	--	--	1.66E-05	1.647	0.014	0.15
Chromium +6	1.35E-05	4.941	0.033	--	--	--	3.32E-06	1.647	0.003	0.036
Cobalt	4.98E-04	4.941	1.23	--	--	--	7.20E-05	1.647	0.059	1.3
Copper	7.23E-05	4.941	0.18	--	--	--	1.71E-04	1.647	0.14	0.32 ^a
Dioxin	7.18E-12	4.941	1.8E-08	--	--	--	--	1.647	--	1.8E-08
Furan	3.75E-10	4.941	9.3E-07	--	--	--	--	1.647	--	9.3E-07
Formaldehyde	6.77E-04	4.941	1.67	--	--	--	2.20E-04	1.647	0.18	1.85
Hydrogen Chloride	3.70E-02	4.941	91.409	--	--	--	7.90E-02	1.647	65.06	156.5 ^a
Indium	1.27E-04	4.941	0.31	--	--	--	--	1.647	--	0.31
Manganese	7.98E-04	4.941	1.97	--	--	--	3.10E-05	1.647	0.026	2.0
Molybdenum	2.54E-04	4.941	0.63	--	--	--	8.83E-05	1.647	0.073	0.70
Nickel	4.41E-05	4.941	0.11	--	--	--	1.02E-03	1.647	0.84	0.95 ^a
Phosphorus	3.53E-04	4.941	0.87	--	--	--	8.60E-04	1.647	0.71	1.58 ^a
Selenium	UD	4.941	--	--	--	--	5.34E-05	1.647	0.044	0.044 ^a
Silver	2.94E-05	4.941	0.073	--	--	--	--	1.647	--	0.073
Thallium	UD	4.941	--	--	--	--	--	1.647	--	--
Tin	1.62E-04	4.941	0.40	--	--	--	8.83E-05	1.647	0.073	0.47
Zinc	4.24E-04	4.941	1.05	--	--	--	3.49E-04	1.647	0.29	1.3
Zirconium	9.29E-05	4.941	0.23	--	--	--	--	1.647	--	0.23

Note: UD = undetectable levels in gas stream.

^a Denotes maximum annual emissions for any fuel scenario.

2.6 STACK PARAMETERS

Stack parameters for the cogeneration facility are presented in Table 2-12. Each of the two new boilers within the proposed facility will be served by a separate stack. Each stack will be 180 feet (ft) tall and 7 ft in diameter. The locations of the two stacks are shown in Figure 2-5.

2.7 CONTROL EQUIPMENT INFORMATION

The proposed facility will utilize several emission control techniques to reduce emissions. The proposed cogeneration facility will incorporate a selective non-catalytic reduction (SNCR) system to reduce NO_x emissions. SNCR is a system which uses ammonia or urea injection into the boiler to reduce NO_x emissions. Further, the cogeneration boilers will minimize CO and VOC through proper furnace design and good combustion practices, including: control of combustion air and temperatures; distribution of fuel on the combustion surface; and better controls over the furnace loads and transient conditions. Particulate emissions will be reduced by an ESP. Mercury emissions will be controlled through a carbon injection system (or equivalent) and the ESP system.

2.8 PERMIT APPLICATION FORMS

A completed air construction permit application form for the proposed facility is contained in Appendix D.

2.9 COMPLIANCE DEMONSTRATION

Sol-Energy will demonstrate compliance with the maximum heat input limits for the facility by monitoring fuel input rates and fuel characteristics on a periodic basis. In addition, steam production parameters (i.e., steam amount, pressure, and temperature) and feedwater parameters will be continuously monitored to allow calculation of heat input by use of an assumed heat transfer efficiency for each fuel.

Continuous stack gas monitoring for opacity, NO_x, CO, and oxygen or CO₂ will be performed. In addition, per the zoning conditions recommended by Palm Beach County and agreed to by Sol-Energy, stack testing will be performed for PM, NO_x, CO, SO₂, lead, mercury and VOC

Table 2-12. Stack Parameters for Sol-Energy Cogeneration Facility

	Fuel Scenario		
	Biomass	Oil	Coal
Stack Height (ft)	180	180	180
Stack Diam. (ft)	7.0	7.0	7.0
Gas Flowrate (acfm)	223,800 - 283,600	153,500	197,400
Gas Velocity (ft/s)	96.9 - 122.8	66.5	85.5
Gas Temperature (F)	350	350	350

Note: acfm = actual cubic feet per minute.
 F = degrees Fahrenheit.
 ft = feet.
 ft/s = feet per second.

every 6 months during the first 2 years of operation. If these tests show compliance with the permitted emission limits, the stack testing frequency will be reduced to that typically required by FDER (i.e., once every year or once every 5 years, depending upon pollutant).

Monitoring of SO₂ emissions due to oil and coal burning will be based on fuel analysis data.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to Sol-Energy's proposed cogeneration facility. These regulations must be satisfied before construction can begin on the proposed facility.

3.1 NATIONAL AND STATE AAQS

The existing national and Florida ambient air quality standards (AAQS) are presented in Table 3-1. National primary AAQS were promulgated to protect the public health, and national secondary 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

Federal PSD requirements are contained in the Code of Federal Regulations (CFR), Title 40, Part 52.21, Prevention of Significant Deterioration of air quality. The State of Florida has adopted PSD regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)] that essentially are identical to the federal regulations. PSD regulations require that all new major stationary sources or major modifications to existing major sources of air pollutants regulated under CAA be reviewed and a construction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by the U.S. Environmental Protection Agency (EPA), and, therefore, PSD approval authority in Florida has been granted to FDER.

A "major facility" is defined under PSD regulations as any one of 28 named source categories that has the potential to emit 100 tons per year (TPY) or more of any pollutant regulated under the CAA, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. A "source" is defined as an identifiable piece of process equipment or emissions unit. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant, considering the application of control equipment and any other federally enforceable limitations on the source's capacity. A "major modification" is defined under PSD regulations as a change at an existing major stationary facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels ($\mu\text{g}/\text{m}^3$)

Pollutant	Averaging Time	AAQS			PSD Increments		Significant Impact Levels
		National		State of Florida	Class I	Class II	
		Primary Standard	Secondary Standard				
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum ^a	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4 ^c	17 ^c	1
	24-Hour Maximum ^b	150	150	150	8 ^c	30 ^c	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum ^b	365	NA	260	5	91	5
	3-Hour Maximum ^b	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum ^b	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum ^b	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum ^d	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

^a Maximum concentration not to be exceeded more than once per year.^b Achieved when the expected number of exceedances per year is less than 1.^c Proposed by EPA in the Federal Register on October 5, 1989.^d Achieved when the expected number of days per year with concentrations above the standard is less than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.

Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

 $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.

40 CFR 50.

40 CFR 52.21.

Chapter 17-2.400, F.A.C.

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	<u>De Minimis</u> Monitoring Concentration ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY ^a
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
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour

^a No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

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.

NSPS = New Source Performance Standards.

NESHAP = National Emission Standards for Hazardous Air Pollutants.

$\mu\text{g}/\text{m}^3$ = micrograms per cubic meter.

Source: F.A.C., Rule 17-2.510, Table 500-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Major new facilities and major modifications are required to undergo the following analyses related to PSD for each pollutant emitted in significant amounts:

1. Source information,
2. Control technology review,
3. Source impact analysis,
4. Preconstruction air quality monitoring analysis, and
5. Additional impact analyses.

In addition to these analyses, a new source also must be reviewed with respect to good engineering practices (GEP) stack height regulations. If the proposed new source or modification is located in a nonattainment area for any pollutant, the source may be subject to nonattainment new source review requirements.

Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

The 1977 CAA amendments address the prevention of significant deterioration of air quality. The law specifies that certain increases in air quality concentrations above the baseline concentration level of SO₂ and PM(TSP) would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or will have an impact. Congress also directed EPA to evaluate PSD increments for other criteria pollutants and, if appropriate, promulgate PSD increments for such pollutants.

Three classifications were designated, based on criteria established in the CAA amendments. Certain types of areas (international parks, national wilderness areas, memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) were designated as Class I areas. All other areas of the country were designated as Class II. PSD increments for Class III areas were defined, but no areas were designated as Class III. However, Congress made provisions in the law to allow the redesignation of Class II areas to Class III areas.

In 1977, EPA promulgated PSD regulations related to the requirements for classifications, increments, and area designations as set forth by Congress. PSD increments were initially set for

only SO₂ and PM(TSP). However, in 1988, EPA promulgated final PSD regulations for NO_x and established PSD increments for nitrogen dioxide (NO₂).

The current federal PSD increments are shown in Table 3-1. As shown, Class I increments are the most stringent, allowing the smallest amount of air quality deterioration, while the Class III increments allow a greater amount of deterioration. FDER has adopted the EPA class designations and allowable PSD increments for PM(TSP), SO₂, and NO₂. The Florida NO₂ increments were adopted in August 1990.

On October 5, 1989, EPA proposed PSD increments for PM₁₀. Those proposed increments are shown in Table 3-1. The PM₁₀ increments as proposed are somewhat lower in magnitude than the current PM(TSP) increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a fictitious concentration level corresponding to a specified baseline date and certain additional baseline sources. In reference to the baseline concentration, the baseline date actually includes three different dates:

1. The major source baseline date, which is January 6, 1975, in the cases of SO₂ and PM(TSP), and February 8, 1988, in the case of NO₂;
2. The minor source baseline date, which is the earliest date after the trigger date on which a major stationary source or major modification subject to PSD regulations submits a complete PSD application; and
3. The trigger date, which is August 7, 1977, for SO₂ and PM(TSP), and February 8, 1988, for NO₂.

By definition in the PSD regulations, 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 sources in existence on the applicable minor source baseline date; and

2. The allowable emissions of major stationary facilities that began construction before January 6, 1975, for SO₂ and PM(TSP) sources, or February 8, 1988, for NO_x sources, but which were not in operation by the applicable baseline date.

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

1. Actual emissions representative of a major stationary source on which construction began after January 6, 1975, for SO₂ and PM(TSP) sources, and after February 8, 1988, for NO_x sources; and
2. Actual emission increases and decreases at any stationary facility occurring after the major source baseline date that result from a physical change or change in the method of operation of the facility.

The minor source baseline date for SO₂ and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.). The minor source baseline date for NO₂ has been set as March 28, 1988, for all of Florida.

3.2.3 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 [Chapter 17-2.500(5)(c), 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).

BACT is defined in Chapter 17-2.100(25), F.A.C. as:

An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, 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 such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source 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.

The requirements for BACT were promulgated within the framework of PSD 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 EPA's Guidelines for Determining Best Available Control Technology (BACT) (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). 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. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. 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. Therefore, BACT analyses must be conducted on a case-by-case basis.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed 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 proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). 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).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limits that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990a).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(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 proposed 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 is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is 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 EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

Under the exemption rule, FDER may exempt a proposed major stationary facility or major modification 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 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD 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 (EPA, 1987b). The source impact analysis for criteria pollutants can be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below specified significance levels, as presented in Table 3-1.

EPA and the National Park Service are currently developing significant impact levels for Class I areas. The significance levels have not yet been finalized. Proposed significance levels for the Class I areas are discussed in Section 6.0.

Various lengths of record for meteorological data can be used for impact analyses. 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 less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor must normally be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSES

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analysis of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts from 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 (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA amendments require that the degree of emission limitation required for control of any pollutant not 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, 1985). Identical regulations have been adopted by FDER [Chapter 17-2.270, 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:

$$H_g = H + 1.5L$$

where: H_g = 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 five times the lesser of the height or width dimensions of a structure or terrain feature but not greater than 0.8 kilometers (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.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant, or if the modification results in a significant net emission increase of the nonattainment pollutant.

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located

within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 PSD REVIEW

3.4.1.1 Pollutant Applicability

The cogeneration facility site is located in Palm Beach County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants except ozone. Accordingly, VOC emissions are regulated under the nonattainment regulations, rather than PSD rules. Palm Beach County and surrounding counties are designated as PSD Class II areas for SO₂, PM(TSP), and NO₂. The site is approximately 120 km north of the nearest PSD Class I area, which is the Everglades National Park in Dade County.

The Osceola Farms sugar mill is considered to be an existing major facility because potential emissions of any regulated pollutant exceed 100 TPY. As a result, PSD review is required for the proposed modification for each pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., a major modification).

Baseline emissions for PSD source applicability are based on emission factors and the last two calendar years (1990-1991) of operational data from the Osceola Farms sugar mill. For bagasse, the particulate matter (PM) emission factor in terms of lb PM/lb steam was determined from stack test results under measured steam production. The tests were performed on each boiler separately. The total steam produced during the year is not exclusively from bagasse; a portion is from oil firing. By determining the fuel inputs during the years, the total amount of steam due to bagasse firing was determined. The emission factors for bagasse were then applied to the steam rate produced from bagasse.

Industry test data was used for determining emission factors for SO₂, NO_x, CO, and VOC due to bagasse firing. Further, for NO_x, an average was taken between the industry average and the AP-42 value. The emission factor for mercury emissions due to bagasse burning is the same as the factor used to estimate future mercury emissions (refer to Section 2.0), except that current emissions reflect no mercury control system. Emission factors for lead were obtained from tests

conducted at Seminole Kraft Corporation in 1990 on wood fired boilers. Also from these tests, there were no detectable emissions of beryllium or fluoride.

Sulfuric acid mist emissions for both bagasse and No. 6 fuel oil are based upon EPA AP-42, which indicates sulfuric acid mist is approximately 3 percent of sulfur dioxide emissions.

Emission factors for the burning of No. 6 fuel oil is provided in AP-42 (EPA, 1988). Emission factors for PM (2.4% sulfur fuel oil), SO₂, NO_x, CO, and VOC were obtained from this source. The emission factor for mercury is based upon average content in the No. 6 fuel oil. (KBN, 1992)

Beryllium and lead emission factors for oil firing were obtained from Toxic Air Pollutant Emission Factors, Second Edition (EPA, 1990c). The fluoride emission factor was obtained from Emissions Assessment of Conventional Stationary Combustion Systems: Volume V (EPA, 1981).

The baseline emissions for Osceola Farms for each regulated pollutant are presented in Table 3-3. Detailed calculations and derivations for the emission factors and source activity factors are presented in Appendix B.

Also shown in Table 3-3 are the maximum annual emissions for the cogeneration facility. The net increase in maximum annual emissions from the proposed cogeneration facility project are compared to the PSD significant emission rates in Table 3-3. As shown, potential emissions of SO₂, fluoride (Fl), beryllium (Be), and sulfuric acid mist will exceed the PSD significant emission rate. Therefore, the proposed facility is subject to PSD review for these pollutants. Annual emissions of particulate matter, NO_x, CO, VOCs, and Pb will be reduced as a result of the proposed project.

3.4.1.2 Ambient Monitoring

Based upon the increase in emissions due to the proposed project, a PSD preconstruction ambient monitoring analysis is required for SO₂, Fl, Be and sulfuric acid mist. However, if the increase in impacts of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Table 3-3. PSD Source Applicability Analysis for Sol-Energy Cogeneration Facility

Regulated Pollutant	Baseline Emissions (TPY)	Cogeneration Facility Annual Emissions (TPY)	Net Change (TPY)	Significant Emission Rate (TPY)	PSD Applies ?
Particulate (TSP)	357.7	109.3 ^a	-248.4	25	No
Particulate (PM10)	321.9	106.7 ^b	-215.2	15	No
Sulfur dioxide	178.5	1,071.5	893.0	40	Yes
Nitrogen oxides	437.8	436.5	-1.3	40	No
Carbon monoxide	5,992.3	1,225.0	-4,767.3	100	No
Volatile org. compds.	208.6	210.0	1.4	40	No ^c
Lead	0.16	0.11	-0.05	0.6	No
Mercury	0.0137 ^d	0.0139	0.0002	0.1	No
Beryllium	0.00002	0.00490	0.00488	0.0004	Yes
Fluorides	0.0079	19.8	19.8	3	Yes
Sulfuric acid mist	5.36	31.1	25.7	7	Yes
Total reduced sulfur	--	--	0	10	No
Asbestos	--	--	0	0.007	No
Vinyl Chloride	--	--	0	0	No

^a Includes 105.0 TPY from boilers and 4.3 TPY from fugitive dust emission sources.

^b Includes 105.0 TPY from boilers and 1.7 TPY from fugitive dust emission sources.

^c Nonattainment review does not apply since the increase in VOC emissions is less than 40 TPY.

^d The estimated annual average emission rate for the most recent 2 years is 0.0137 TPY. The highest annual emission rate for either of the last 2 years is 0.0139 TPY.

The maximum 24-hour average SO₂ concentration due to the proposed cogeneration units only is predicted to be 106 micrograms per cubic meter (μg/m³). The methodology used to predict these impacts is presented in Section 6.0, along with the impact analysis results. The de minimis concentration level for SO₂ is 13 μg/m³, 24-hour average (see Table 3-2). The maximum 24-hour SO₂ impacts are greater than the de minimis level, and, therefore, an ambient monitoring analysis is required for SO₂. The monitoring analysis is presented in Section 4.0. There is no acceptable monitoring method for sulfuric acid mist; therefore this pollutant is exempt from the preconstruction monitoring requirements.

For non-criteria pollutants such as FI and Be, it is EPA's policy not to require ambient monitoring (EPA, 1987a). Modeling results will be used to determine if impacts of these pollutants are acceptable.

3.4.1.3 GEP Stack Height Analysis

The GEP stack height regulations allow any stack to be the highest of at least 65 m [213 feet (ft)] high or a height established by applying the formula:

$$H_g = H + 1.5L$$

where: H_g = GEP stack height,

H = Height of the structure or nearby structure, and

L = Lesser dimension (height or projected width) of nearby structure(s)

The boiler buildings are the significant structures associated with the proposed cogeneration facility. The buildings have a height of 123 feet and a total combined width of 138 ft. From the above formula, the GEP stack height is $123 + (1.5 \times 123) = 308$ ft. The two stacks for the proposed facility will be 180 ft high and therefore do not exceed the GEP stack height. The potential for downwash of the emissions from the facility due to the presence of nearby structures is discussed in Section 6.0, Air Quality Impact Analysis.

3.4.2 NONATTAINMENT REVIEW

The cogeneration facility site is located in Palm Beach County, which has been designated as a nonattainment area for ozone. Nonattainment review applies if the increase of VOC emissions due to the proposed facility is greater than 40 TPY of VOC. As shown in Table 3-3, there will be a net increase in VOC emissions of only 1.4 TPY. Consequently, nonattainment new source review does not apply to the proposed project.

4.0 PRECONSTRUCTION AMBIENT MONITORING ANALYSIS

As discussed in Section 3.3, Source Applicability, a preconstruction ambient monitoring analysis is required for SO₂. The preconstruction monitoring analysis is presented in this section.

Guidelines concerning the requirements for PSD preconstruction monitoring are given in the document entitled "Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)" (EPA, 1987a). The guidelines cover the collection of new data to fulfill the requirements, as well as the use of existing representative air quality data. To determine if existing data are "representative", the major considerations are monitor location, quality of the data, and currentness of data.

The Florida Sugar Cane League (FSCL) has operated an ambient monitoring network in the sugar cane growing area for several years. The network contains one continuous ambient SO₂ monitor, located at the Florida Celery Exchange in Belle Glade. This site is about 15 km southwest of the Osceola Farms sugar mill. Data collected from the station are summarized in Table 4-1 for the period January 1989 through August 1991.

The first criterion in determining if existing data are representative is monitor location. According to the PSD guidelines, a "regional" monitoring site may be used if the proposed source will be located in an area that is generally free from the impact of other points and area sources associated with human activities. The regional site must be located in an area of similar terrain and represent the air quality across a broad region. The SO₂ monitoring site in Belle Glade meets this criterion.

The second criterion relates to the quality of the monitoring data (i.e., the data must meet all PSD quality assurance requirements). The FSCL monitoring network has had full PSD approval for several years and meets the PSD requirements.

The third criterion states that the data must be current. Generally, this means the data must not be more than 3 years old. The data presented in Table 4-1 were collected within the past 3 years and therefore meet the PSD criteria.

Table 4-1. SO₂ Concentrations Measured at the Monitoring Station in Belle Glade

Site Number	Location	Period	Number of Observations	Measured Concentration (µg/m³)				Annual
				3-Hour		24-Hour		
				Highest	Second Highest	Highest	Second-Highest	
3420-017-J02	Belle Glade: Duda Rd, 1 mile south of Old SR 80	Jan - Dec 1989	5,974	50	42	19	19	8
		Jan - Sept 1990	5,611	67	53	30	21	8
		Jan - Aug 1991	4,279	34	30	16	14	4

In summary, the continuous SO₂ data collected at the monitoring site in Belle Glade fulfills the PSD preconstruction monitoring criteria. The data therefore should satisfy the preconstruction monitoring requirements for SO₂.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY EVALUATION

As presented in Section 3.4, the net increase in the emissions of SO_2 , Be , F , and sulfuric acid mist from the proposed Sol-Energy cogeneration project will exceed their respective PSD significant emission rates when coal is fired as an auxiliary fuel (see Table 3-3). Therefore, BACT analyses for these four pollutants is required for the proposed spreader stoker boilers firing bituminous coal. The complete "top-down" BACT evaluation for each PSD pollutant includes the identification of the respective control technologies; the environmental, energy, and economic impact evaluations of all technically feasible control methods; and the BACT analysis summary.

5.1 BACT DETERMINATION FOR SULFUR DIOXIDE (SO_2) EMISSIONS

5.1.1 IDENTIFICATION OF SO_2 EMISSION CONTROL TECHNOLOGIES FOR UTILITY BOILERS

In this Section, the available control technologies capable of reducing SO_2 emissions produced from firing eastern bituminous coal as an auxiliary fuel will be evaluated. Potential application as BACT for the two proposed spreader stoker boilers, rated on coal at 460 MMBtu/hr each, is discussed.

In boilers firing fossil fuels, sulfur compounds are produced by the combustion process in which nearly complete oxidation of the fuel-bound sulfur occurs. These sulfur compounds are primarily SO_2 , with a smaller quantity of sulfur trioxide (SO_3) that eventually converts into acid mist. 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 the firing mechanism does not affect SO_2 emissions. Generally, complete oxidation of sulfur in fuel is readily achieved before the complete combustion of the primary carbon fuel element in fossil fuel. Typically, SO_2 emission reduction is accomplished by treating the flue gas with a variety of flue gas desulfurization (FGD) processes.

Standard FGD processes for spreader stoker boilers are add-on SO_2 scrubbers of either the wet or dry type. The following discussion of each potential add-on scrubber type for SO_2 removal includes a description of the technology and, if it is concluded that the technology is technically feasible, the potential SO_2 emission reduction level.

Wet Scrubbing Systems

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 creates a liquid waste stream. Therefore, a wastewater treatment and disposal system is generally required for 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. Either sodium-based, calcium-based, or dual-alkali-based chemicals are used from which the scrubber systems are named, such as the sodium-based scrubber, the dual-alkali scrubber, and the wet lime/limestone scrubber. Packed towers are used for the sodium-based scrubbing system, whereas spray towers are generally used for the lime/limestone scrubbing systems. A brief description of each wet scrubbing system is described below.

The sodium scrubbing systems use either a sodium hydroxide (NaOH) or a sodium carbonate (CaCO_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., NaSO_3) initially, then sulfate (NaSO_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 up to 95 percent SO_2 reduction, they have not been used commercially on large utility boilers and therefore are considered as unproven.

The dual-alkali scrubbing process uses the sodium-based liquor to scrub the SO_2 from the flue gas, then calcium-based chemicals are used to regenerate the sodium hydroxide or NaCO_3 solution. The sodium scrubbing and the dual-alkali scrubbing processes are not commercially available or proven for large coal-fired boilers. The primary reasons for not using the sodium-based system are the expensive cost of premium chemicals, less availability of sodium-based chemical, and the highly alkaline waste liquid produced. The dual-alkali system also presents similar undesirable effects if applied to coal-fired boilers. It will be shown later in the discussions of the BACT/LAER clearinghouse information for coal-fired boilers that neither the sodium-based systems nor the dual-alkali systems have been determined to be BACT for any coal-fired facility.

Therefore, the sodium-based and the dual-alkali scrubbing processes are considered as technically infeasible for the proposed project and both technologies are eliminated from any further consideration as BACT.

The wet scrubbing system that is most widely used for SO₂ removal in large coal-fired utility boilers is the calcium-based wet FGD system. It is estimated that approximately 82 percent of the coal-fired megawatt capacity in the United States is equipped with this FGD technology.

Depending on whether lime or limestone is used, the SO₂ reacts with the hydrate or carbonate to form calcium sulfite (i.e., CaSO₃ • ½ H₂O) initially, then sulfates (i.e., CaSO₄ • 2H₂O) with further oxidation. The calcium sulfite or sulfate slurry is insoluble which requires settling ponds and separation equipment and a wastewater treatment facility in order to properly handle the solid and wastewater disposal.

The most frequently utilized wet FGD technology is the wet limestone system. The preferred version of the 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 usually 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 carbonate reagent. A bleedstream is taken off from the recycled slurry stream to avoid build-up inside the spray tower. The scrubbing reaction produces calcium sulfite as the byproduct. Many systems further oxidize the sulfite into calcium sulfate, which is easier to dewater. Byproducts and unreacted reagent in the bleedstream is dewatered using a variety of equipment including thickeners, centrifuges, and vacuum filters. Dewatering systems reduce the water content in the filtered waste solid to between 10 to 50 percent by weight, depending on the system.

Several wet scrubber systems utilize lime rather than limestone as the alkaline 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 limestone pebbles. While a limestone system requires more initial capital costs for auxiliary equipment (i.e., limestone pulverizer, conveyor and slaker

system, etc.), the lower operating cost of the reagent provides a substantial annual savings. This is especially beneficial for a facility using medium and high sulfur coals, where considerably more reagent chemicals are needed.

Technically, wet lime/limestone scrubbing processes are capable of reducing SO_2 emissions with a removal efficiency between 70 to 93 percent. Theoretically, a higher efficiency of up to 95 percent may be achievable by adding adipic acid to the scrubbing liquid because the reactions between the lime and limestone with SO_2 are more favorable at lower pH levels. Process controls for the wet FGD technology have not advanced precisely enough to confidently state that performance at one location can be duplicated at another. Margins of allowances must be applied to the best performances achieved at other plants. Since the wet lime/limestone scrubbing processes can potentially achieve 95 percent removal efficiency, the 95 percent will be used in this analysis.

Dry Scrubbing System

In the dry scrubbing 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 the gaseous SO_2 and formation of alkaline salts are not clear. Overall, the SO_2 gas reacts with lime or sodium sorbent to form initially either calcium sulfite ($\text{CaSO}_3 \cdot \frac{1}{2}\text{H}_2\text{O}$) or sodium sulfite (Na_2SO_3). Upon further oxidation or SO_2 absorption enhanced by the drying process, the sulfite salts will transform into calcium sulfate ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$) or sodium sulfate solids. A typical spray dryer will use lime as the reagent because it is more readily available than sodium carbonate.

Lime slurry is injected into the spray dryer chamber through either a rotary atomizer 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 the lime 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 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 pseudo liquid-solid phase salts that are then dried into insoluble crystals by the heat content of the flue gases. The spray dryer chamber is designed to provide sufficient contact and residence time to complete the above 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 spray dryer scrubber contains fly ash, dried calcium salts and dried unreacted lime. 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 spray dryer 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 spray dryer scrubber is typically 18 to 30°F above adiabatic saturation. The "dry" reaction products and coal fly ash are both removed from the flue gas by a particulate collection device downstream. This differs from the wet scrubber system, wherein the slurry leaving that system must be dewatered at great cost and the gas is cooled to adiabatic saturation temperature.

Key design and operating parameters that can significantly affect spray dryer 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 spray dryer 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 sulfur dioxide removal occur at temperatures close to adiabatic saturation, but the flue gas temperature must be kept high enough to ensure the slurry and reaction products are adequately dried prior to the particulate collection process.

The dry scrubber usually is located upstream of the particulate control device, which is either an electrostatic precipitator (ESP) or a fabric filter (baghouse) system. A baghouse can provide slightly greater SO₂ removal compared to an ESP system. When a baghouse is used, a layer of porous filter cake forms on the filter bag surfaces. This filter cake contains unspent reagent which provides a site for additional SO₂ removal since the flue gases pass through the filter cake.

Based on BACT determinations previously issued, the spray dryer FGD system can achieve between 70 to 95 percent SO₂ removal for coal-fired boilers, with the majority designed for 92 percent removal (EPA, 1992a). The higher removal efficiencies of greater than 90 percent can be achieved by maintaining an optimum ratio of reagent and SO₂ gas and using a fabric filter for particulate removal. Discussions with FGD vendors indicate that a 92 percent control efficiency is a prudent guarantee based on higher efficiencies being unproven on this relatively new technology and use of an ESP as the PM control device. As a result, a 92 percent SO₂ removal was used for the BACT analysis for the spray dryer.

Low-Sulfur Coal

The sulfur content of eastern bituminous coal ranges from 0.5 to 3.0 percent by weight for eastern bituminous coal. Since the level of SO₂ emissions is directly related to the amount of sulfur in the fuel, a low-sulfur-containing fuel can be used to meet the SO₂ emission limitation specified by the NSPS regulations for electric utility steam boilers.

Under the current NSPS regulations for electric utility steam generators (40 CFR 60, Subpart Da), a heat specific SO₂ emission rate of 1.2 lb/MMBtu must be met by the proposed boilers. The boilers have been classified as resource recovery units because the proposed primary fuels are biomass that include bagasse and wood waste. The average sulfur content of eastern bituminous coal is 2 percent which is equivalent to a SO₂ emission factor of approximately 3.33 lb/MMBtu. Sol-Energy is proposing to use 0.7 percent sulfur coal to meet the NSPS limit, and will limit total annual SO₂ emissions from both Sol-Energy and Flo-Energy (Osceola and Okeelanta) cogeneration projects combined to an average of 1,000 TPY over the life of these projects.

5.1.2 EVALUATION OF TECHNICALLY FEASIBLE SO₂ CONTROL METHODS FOR COAL FIRING

This section examines the two technically feasible alternative SO₂ control methods (i.e., the wet lime scrubber and the lime spray dryer scrubber) identified in the previous discussion. Each

alternative will be further examined with regard to its technical issues, environmental effects, energy requirements and impacts, and economic impacts.

Presented in Table 5-1 is a summary of all BACT determinations for SO₂ emissions from spreader stoker and pulverized-coal-fired boilers issued since 1986. This information was obtained from the BACT/LAER Informational System (BLIS) database through EPA's National Computer Center located at Research Triangle Park in North Carolina, and from regulatory agencies in various states that were contacted.

5.1.2.1 Ranking of Feasible Control Technologies

A baseline emission level must be established as the basis for top-down BACT ranking and for economic analysis purposes. The baseline is defined as the uncontrolled rate of a process being reviewed. Thus, the SO₂ emission level associated with the firing of 0.7 percent sulfur eastern bituminous coal and no add-on SO₂ controls will be used as the baseline emission level.

Presented in Table 5-2 is the BACT top-down hierarchy of both proposed SO₂ reduction methods, their general ranges of control effectiveness, and their design control efficiencies applied to the proposed boilers. As discussed previously, the wet limestone scrubber and lime spray dryer scrubber can be designed to achieve SO₂ removal efficiencies of 95 and 92 percent, respectively. Therefore, the BACT top-down hierarchy ranks the wet lime/limestone scrubber first and the lime spray dryer process second. The wet scrubber option will be first compared to the dry scrubbing option in terms of total and incremental values, and then the dry scrubbing option will be compared to the low sulfur coal option.

It is noted that, for the proposed Sol-Energy boilers, an FGD system would be operated only when burning coal, due to the very low sulfur content of biomass fuels. Thus, the baseline SO₂ emissions shown in Table 5-2 reflect the SO₂ emissions due only to coal burning.

5.1.2.2 Analysis of Add-On FGD Systems

Technical Issues--The wet limestone absorber is a "first generation" scrubber that can typically achieve SO₂ removal efficiencies in the 70 to 95 percent range. The wet scrubber design has included packed towers and medium-to-high pressure drop venturis, and many were designed for

Table 5-1. Summary of BACT Determinations for SO2 Emissions from Coal-fired External Combustion Boilers

Company Name	State	Permit Number	Permit Issued Date	Boiler Throughput (MMBtu/hr)	Boiler Type	Fuel Type	SO2 Emission Limit		Comments	Eff. (%)
							(lb/hr)	(lb/MMBtu)		
Cogentrix of Dinwiddie	VA	51021	16-Apr-92	375	SSB, 8 Ea.	--	48.8	0.13	Lime Spray Dryer/Fabric filter	90%
Hadson Power 14, Buena Vista	VA	21130	08-Apr-92	379	SSB	Coal	42.3	0.112	Lime Injection	93%
Orl. Util. Comm., Stanton NRG Unit 2	FL	PSD-FL-084	23-Dec-91	4,286	PC	Coal	--	0.25	Wet Limestone FGD 30D Rol Avg.	92%
PG&E/Bechtel Generating Co.	FL	PSD-FL-???	06-Sep-91	3,422	PC	Coal	581.7	0.17	Lime Spray Drying	95%
Old Dominion Electric Cooperative	VA	30867	29-Apr-91	2,042.5	PC, 2 Ea.	BC, 1-1.3% S	--	0.156	Wet Limestone FGD 30D Rol Avg.	94%
Multitrade Limited Partnership*	VA	30871	08-Apr-91	356.3	SSB, 3 Ea.	Coal 0.85% S & Wood	71.3	0.2	Uncontrolled	--
Roanoke Valley Project	NC	6964	24-Jan-91	1700.0	PC	--	--	0.213	Dry Lime FGD	92%
Cogentrix of Richmond	VA	51033	02-Jan-91	375	SSB, 8 Ea.	EB Coal, 1.1% S	48.8	0.13	Dry Scrubber/Baghouse	90%
Keystone	NJ	--	1991	--	PC	--	--	--	--	--
Chambers Work Project	NJ		01-Oct-90	220MW	PC	--	--	--	--	--
Thomaston Mills, Inc.	GA	2211-145-10559	21-Sep-90	214.75	SSB	Coal, 1.5% S	--	0.23	Spray Dryer w/ Lime Inj.	90%
Wisconsin Electric Power Co.	WI	90-POY-037	05-Sep-90	--	--	--	--	--	--	--
Hadson Power 13, Hopewell	VA	51019	17-Aug-90	379	--	Coal 1.3% S Max	61.3	0.162	Lime Spray Dryer	92%
Mecklenburg Cogeneration	VA	30861	18-May-90	834.5	PC, 2 Ea.	Coal, 1% S Ann Avg.	143.5	0.172	Water-lime Spray Dryer & FF	92%
Logan Township Power Plant	NJ	--	1990	--	PC	--	--	--	Lime Spray Dryer FGD	--
Hadson Power II	VA	61093	22-Nov-89	379	--	Coal 1.3% S Max	61.3	0.162	Lime Injection	92%
Intermountain Power Project	UT	BAQE-672-89	24-Oct-89	8,352	--	--	--	0.150	430,922 TPY Coal; 1.6 MM GPY Res Oil	--
Cogentrix of Rocky Mount	NC	6563	20-Jul-89	375	SSB, 4 Ea.	Coal	--	0.31	Dry Lime FGD	--
P.H. Glatfeller Co.	PA	67-306-006	11-Feb-88	633	Boiler	BC & Wood Waste	--	1.2	Limestone Inj. 90%.	--
Holly Farms Poultry Ind.	NC	3354R7	30-Nov-87	99	--	Coal/Wood	158.4	1.6	Low Sulfur Coal, 0.94% S	--
Cogentrix Michigan Leasing Corp.	MI	48-87	31-Jul-87	214	SSB, 3 Ea.	Coal, 3% S Max.	357.4	1.67	Lime Spray Dryer, Max. 3% S	90%
Utah Power & Light Co.	UT	--	27-Jul-87	400 MW	--	Coal	--	1.20	NSPS	80%
Multitrade of Martinsville	VA	30826	24-Jul-87	120	Cogen Boiler	30% Coal & 70% Wood	155.98	1.2	Uncontrolled for NSPS, 0.8% S 30D Rol Avg.	--
Deseret Generation & Transmission	UT	BAQ-0913-1	02-Jul-87	400MW	PC	--	209.0	0.055	Limestone FGD	--
WM. H. Zimmer Generation Station	OH	14-1036	05-Feb-87	11,968	PC	Coal	6,558.5	0.548	Magnesium-Enhanced Lime FGD	91%
Archbald Power Corp.	PA	35-306-001	16-Jan-87	240	--	AC, 0.317% S	36	0.15	Limestone Injection	90%

* Permit Change to Burn only Wood

Note: SSB = Spreader Stoker Boiler; PC = Pulverized Coal; BC = Bituminous Coal; AC = Anthracite Coal.

Table 5-2. BACT "Top-down" Hierarchy of SO2 Reduction Methods for the Proposed Boilers.

Top-down Ranking	Technology	Range of Control Effectiveness (%)	Control level for BACT Analysis (%)	SO2 Emission Level (lb/MMBtu)	SO2 Annual Emissions+ (TPY)
First	Wet Lime/Limestone Scrubber	80-95	95	0.06	49.4
Second	Lime Spray Dryer Scrubber	80-92	92	0.10	79.1
Baseline	Low Sulfur Coal	--	--	1.20	988.2

+ Total for the two boilers based on maximum coal firing rate.

simultaneous particulate removal in the same vessel. A number of design and operating problems have been associated with these "first generation" designs, such as:

1. Corrosion caused by high chlorides concentrations and/or improper materials selection and construction,
2. Equipment failure caused by improper equipment selection or design,
3. Scaling and plugging caused by the cementing properties of the calcium salts, improper operation and control, and improper equipment design or control system design, and
4. Solid waste disposal problems caused by the cementing properties and poor dewatering characteristics of calcium sulfite sludge.

As these "first generation" problems were identified, they were corrected by retrofit and by improved system designs. Some specific improvements made to earlier designs include:

1. Using open spray towers in place of packed bed design (e.g., turbulent contact absorbers);
2. Removing particulate separately, thus avoiding the high pressure drop of the venturi and the problems associated with scaling and mud formation, and
3. Relocating induced draft fans from downstream to upstream of the wet scrubbers, where the flue gas is not at saturation, and thus avoiding condensation and formation of acids that cause corrosion problems.

The wet limestone scrubber requires a larger auxiliary system for various processes such as raw materials and slurry preparation, solid and liquid separation, other mixing and aeration operation, and waste handling. Its applicability is generally limited by plant physical limitations because it is a nonregenerable process that generates high solid waste volumes.

The lime spray dryer process requires a particulate control system to be installed downstream and more precise control than the wet scrubber system. From an operating standpoint, a narrow operating temperature window has to be strictly adhered to in order to avoid either potential excessive heating or condensation in the particulate collection equipment downstream. Its long-term reliability is not as proven for coal-fired boilers as the wet limestone scrubber. However, its mechanical operation is less complex than the wet limestone scrubber.

For the proposed Sol-Energy project, startups and shutdowns may occur at irregular intervals because coal will only be used as an auxiliary fuel. It is likely that the scrubbers and their auxiliary equipment will not be operated for long periods of time, potentially as long as several months. For example, during and immediately after the crop season (October-March) the plant will normally operate on biomass fuels since sufficient quantities of bagasse will be available. It is unlikely that coal will be utilized at all during this 5-month period. During the off-season, the supply of biomass may not be consistently adequate to fuel the plant, and coal may need to be burned at irregular intervals. Such operations, with long periods of downtime as well as irregular periods of operation, will be detrimental to the integrity of an FGD system and consequently will likely affect the control efficiency of the system.

Environmental Effects

The primary environmental concern of using the wet limestone system is the process wastewater and the waste sludge generated. These waste streams require proper treatment and disposal. Typically, the waste sludge is landfilled on-site, potentially impacting local groundwater. The wet FGD system for Sol-Energy would generate approximately 2,650 tons of solid sludge each year, which would be landfilled off-site.

The calcium sulfate sludge could be disposed of by further processing to make gypsum that may be used by a wallboard manufacturing facility. However, this option is not viable for the proposed project since there is no known market for the gypsum in the south Florida area. In addition, manufacturers of wallboard have very rigid standards regarding acceptable levels of impurities. Some manufacturers require samples of the product prior to committing to using it since there is the possibility that its characteristics and/or impurities might render it unsuitable. They are not enthusiastic about using the material, since gypsum is a small part of the total cost of wallboard. Firing coal as an auxiliary fuel (with an FGD system) will not produce a sufficient amount of gypsum on a regular basis to render it marketable. The additional capital cost for the gypsum processing equipment would also be a concern based on the uncertainty of coal firing.

A wet limestone scrubber also has the disadvantage of high water consumption. Wet limestone scrubbers for the Sol-Energy cogeneration project will require approximately 38 million gallons of water per year. Such large water demand will have an undesirable environmental effect in south Florida, which is already experiencing declining water supply levels due to increasing demands on water consumption and lower than average rainfall.

Since the flue gas that leaves the wet limestone scrubber is saturated with moisture, there is a potential concern for condensation in the stack unless the flue gas is reheated. This condensation can be corrosive due to its acidic nature. The flue gas is typically reheated by 20 to 50°F to prevent this problem. Reheaters are subject to corrosion and in many cases scale build-up, and are very expensive to operate.

The major environmental issues concerning the use of the lime spray dryer process are solid waste disposal and water demand. Calcium salts will be generated from the dry scrubbing process that will require disposal. For every ton of SO₂ removed, there will be an additional 2.7 tons of solid waste generated. A spray dryer FGD system for Sol-Energy could therefore generate up to 2,450 tons of solid waste each year, which would be landfilled off-site. The estimated maximum water requirement for the spray dryer system at Sol-Energy is approximately 15 million gallons per year.

By using low sulfur coal to meet the NSPS, there will be no additional environmental impacts due to the control technology. SO₂ emissions from both Sol-Energy and Flo-Energy cogeneration facilities combined will be limited to an average of 1,000 TPY. This represents no increase over current SO₂ emissions from the existing Okeelanta and Osceola sugar mills.

Energy Requirements and Impacts

Both the wet limestone scrubber and lime spray dryer scrubber require electricity to drive various mechanical equipment, including fans and pumps. The estimated energy requirement is approximately 5,000 megawatt-hours per year (MW-hr/yr) for the wet limestone scrubber and approximately 2,400 MW-hr/yr for the spray dryer scrubber. These estimated energy requirements are calculated assuming the maximum allowable coal-firing for the facility. By firing compliance fuel (i.e., 0.7 percent sulfur coal) to meet NSPS, no additional energy is required, allowing more energy to be provided for public consumption.

Economic Analysis

This section presents the total capital investment (TCI) and the annualized cost (AC) of both the wet limestone scrubber and the lime spray dryer scrubber processes for the two proposed Sol-Energy cogeneration boilers. Capital costs were developed from basic equipment costs for each process and with standard cost factors for estimating the direct and indirect costs of the emission control systems (EPA, 1990b).

The basic equipment cost for the spray dryer system was based on the average budgetary quotations obtained from ABB-Flakt, Joy Environmental Systems, and United McGill. This average cost is \$2.66 million for two spray dryer scrubbers.

The basic equipment cost for the wet limestone scrubber system is approximately \$5.75 million for the two units, or about 2.16 times the cost of the spray dryer scrubbers. This factor was developed from vendor estimations and comparative costs of wet limestone and lime spray dryer scrubbers described in permit applications.

All operating costs were developed based on an equivalent 1,790 hr/yr operation on coal for each boiler (3,580 hr/yr total for the proposed project). This represents the number of hours at maximum coal-firing capacity to achieve 25 percent of the total facility annual heat input (i.e., 1.647×10^{12} Btu/yr divided by 460×10^6 Btu/hr). Uncontrolled SO₂ emissions are based on the proposed SO₂ emissions of 988.2 TPY from maximum coal firing. Controlled SO₂ emissions are based on 92 percent reduction for the lime spray dryer and 95 percent reduction for the wet lime/limestone scrubber.

The cost estimates for both scrubber systems are presented in Tables 5-3 and 5-4. The total capital investment (TCI) estimated for the lime spray dryer scrubbers is \$6.90 million and for the wet limestone scrubbers is \$14.60 million. The annualized cost for the lime spray dryer scrubber is approximately \$2.52 million, and for the wet limestone scrubber is \$4.79 million.

The annualized cost figures derived above are based on the worst-case condition of firing up to 25 percent coal in a single year (i.e., 988.2 TPY of SO₂). However, Sol-Energy has agreed with the Palm Beach County Zoning Board to limit the total SO₂ emissions from both the Sol-Energy and Flo-Energy (Osceola and Okeelanta) cogeneration facilities combined to an average of 1,000 TPY over the life of these facilities. Consequently, it is appropriate to consider the total cost of SO₂ removal systems at both facilities in determining the true cost effectiveness of SO₂ controls. The costing of the SO₂ removal systems at the proposed Flo-Energy cogeneration facility is shown in a companion permit application. The combined annualized costs for the lime spray dryer scrubbers and the wet limestone scrubbers for Sol-Energy and Flo-Energy are approximately \$6.33 million and \$12.03 million, respectively.

Table 5-3. Capital Cost Estimates for Alternative SO₂ Emission Control Systems for Sol-Energy.

Cost Items	Cost Factors	Spray Dryer	Wet FGD
DIRECT CAPITAL COSTS (DCC):			
(1) Purchased Equipment			
(a) Basic Equipment*	Vendor Quote	\$2,660,000	\$5,745,600
(b) Auxiliary Equipment	included	included	included
(c) Structure Support	0.10 x (1a)	\$266,000	\$574,560
(d) Instrumentation & Controls	0.10 x (1a)	\$266,000	\$574,560
(e) Freight [†]	0.05 x (1a-1d)	\$159,600	\$287,280
(f) Sales Tax (Florida)	0.06 x (1a-1d)	\$191,520	\$344,736
(g) Subtotal	(1a-1f)	\$3,543,120	\$7,526,736
(2) Direct Installation [†]	0.30 x (1g)	\$1,062,936	\$2,258,021
Total DCC:	(1) + (2)	\$4,606,056	\$9,784,757
INDIRECT CAPITAL COSTS (ICC):			
(3) Indirect Installation			
(a) Engineering & Supervision [†]	0.10 x (DCC)	\$460,606	\$978,476
(b) Construction & Field Expenses [†]	0.10 x (DCC)	\$460,606	\$978,476
(c) Construction Contractor Fee [†]	0.05 x (DCC)	\$230,303	\$489,238
(d) Contingencies [†]	0.20 x (DCC)	\$921,211	\$1,956,951
(4) Other Indirect Costs			
(a) Startup & Testing [†]	0.03 x (DCC)	\$138,182	\$293,543
(b) Working Capital	30-day DOC**	\$78,195	\$122,089
Total ICC:	(3) + (4)	\$2,289,102	\$4,818,773
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	\$6,895,158	\$14,603,529

* For the spray dryer, the basic equipment cost is the average of budgetary quotations from ABB-Flakt, Joy Environmental Systems, and United McGill. The basic equipment cost for the wet limestone scrubbers were estimated as 2.16 times the cost for the spray dryer scrubbers. The cost factor was determined from vendor estimates and comparative costs between the wet scrubber and the dry scrubber processes as presented in similar analysis.

** 30 days of direct operating costs, calculated from the annualized cost Table 5-4 (i.e., total DOC/12 months).

[†] Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

Table 5-4. Annualized Cost Estimates for the Alternative SO₂ Control Systems for Sol-Energy.

Cost Items	Basis	Spray Dryer	Wet FGD
DIRECT OPERATING COSTS (DOC):			
(1) Labor			
Operator ²	\$22/hr; 2,945 and 4,435 hr/yr total	\$64,800	\$97,573
Supervisor ¹	15% of operator cost	\$9,720	\$14,636
(2) Maintenance ²	5% of direct capital cost	\$230,303	\$489,238
(3) Replacement Parts	3% of direct capital cost	\$138,182	\$293,543
(4) Utilities			
(a) Electricity	\$85 per MW-hr	\$200,836	\$419,515
(b) Water	\$0.27 / 1,000 gal	\$4,086	\$10,215
(5) Raw Chemicals			
(a) Limestone (97% purity)	\$32 / ton including freight	--	\$68,898
(b) Hydrated Lime (74% purity)	\$140 / ton including freight	\$224,139	--
(6) Solid Disposal	\$27 / ton	\$66,277	--
(7) Sludge Disposal		--	\$71,454
Total DOC		\$938,342	\$1,465,071
INDIRECT OPERATING COSTS (IOC):			
(7) Overhead ¹	60% of operating labor & maintenance	\$182,894	\$360,868
(8) Property Taxes ¹	1% of total capital investment	\$68,952	\$146,035
(9) Insurance ¹	1% of total capital investment	\$68,952	\$146,035
(10) Administration ¹	2% of total capital investment	\$137,903	\$292,071
Total IOC		\$458,700	\$945,009
CAPITAL RECOVERY COST (CRC)	CRF of 0.1627 times TCI	\$1,121,842	\$2,375,994
ANNUALIZED COST (AC):	DOC + IOC + CRC	\$2,518,885	\$4,786,075

¹ Based on catalytic incinerators, from OAQPS Control Cost Manual, Fourth Edition.

² Based on maximum of coal firing for the Sol-Energy cogeneration facility.

5.1.2.3 SO₂ BACT Summary

The BACT analysis for SO₂ control has evaluated the two feasible control alternatives (i.e., the limestone wet scrubber and the lime spray dryer scrubber). This section will summarize the overall technical, environmental, energy, and economic impacts of both alternatives and compare them with the alternative of firing compliance coal.

Comparison of Technical Issues

Wet limestone scrubbers and spray dryer scrubbers can reduce SO₂ emissions by 92 and 95 percent, respectively and are considered technically feasible for the Sol-Energy project. For spreader stoker and pulverized coal-fired utility boilers, both wet and dry FGD scrubber systems have been determined to be BACT (see Table 5-1). SO₂ removal efficiencies range from 90 to 95 percent with the higher range assigned to a wet scrubber system with a long averaging time period for compliance (i.e., 30-day rolling average).

However, there are also three determinations during the last five years that have specified low sulfur coal as BACT for spreader stoker boilers firing multiple fuels in which coal-firing contributes the smaller amount of the total heat input. These determinations were made for Multitrade Limited Partnership of Virginia with a 356.3 MMBtu/hr heat input, Holly Farms Poultry Industries of North Carolina with a 99.0 MMBtu/hr heat input, and Multitrade of Martinsville of Virginia with a 120 MMBtu/hr heat input. Compliance coal was specified for these facilities as 0.85 percent sulfur coal, 0.94 percent sulfur coal, and 0.8 percent sulfur coal, respectively. The Multitrade of Martinsville facility was permitted with the option of firing coal as a fuel for up to 30 percent of its total heat input.

It should be noted that all of the facilities required to use add-on FGD process are firing coal as the primary fuel. In contrast, the multifuel boilers are permitted to fire coal as an auxiliary fuel at a maximum of 30 percent of the total heat input without add-on control requirements.

Therefore, the use of 0.7 percent sulfur coal at up to 25 percent of the total heat input without an FGD system is consistent with recent BACT determinations for multifuel spreader stoker boilers with a limited percentage of coal firing.

Comparison of Environmental Impacts

Both wet and dry FGD processes will produce wastewater and solid waste as byproducts. The wet scrubber produces a large volume of wastewater which must be treated before disposal;

whereas the spray dryer scrubber does not. With the wet limestone scrubber system, the solid waste is generally collected in two separate stages. Fly ash is collected in the upstream mechanical collection device. Calcium salts and unreacted reagent are removed from the scrubber slurry wastestream and dewatered separately. In some systems, the dry ash is mixed with the wet scrubber sludge before disposal. For the spray dryer, both fly ash and calcium salts are collected at the same point where the particulate removal system is installed. These solids must be disposed as a waste material.

Solid wastes generated from firing compliance fuel only will produce the smallest quantity of ash requiring disposal. Sol-Energy will recycle coal ash (i.e., for use in concrete, road bed aggregate, etc.) or dispose of the material in an off-site landfill.

In terms of water use, a wet scrubbing system at Sol-Energy would require about 38 million gallons of water per year and the dry scrubbing system about 15 million gallons. Firing compliance coal would require no additional water usage.

The wet scrubber system produces a visible moisture plume due to its being at the moisture dew point. The spray dryer system plume, being above the dew point, would tend to disperse horizontally and vertically before condensing into a visible plume. However, with cool ambient conditions a plume detached from the chimney would sometimes form. The wet scrubber system would produce a visible moisture plume more frequently than a spray dryer system.

For the case of firing compliance coal without additional controls, the plume rise of the flue gases will be higher because of the higher thermal content of the flue gas. Higher temperatures and lower moisture in the flue gas would mean enhanced plume rise and flue gas dispersion and a less visible plume.

In conclusion, the firing of compliance coal with no add-on controls will have the smallest environmental impacts because there will be less byproduct wastes, no additional water usage, and less of a visible plume.

Comparison of Energy Impacts--Both wet and dry scrubbers will consume additional energy for their operation. The estimated additional energy requirements are approximately 5,000 MW-hr for the wet scrubber system, and approximately 2,400 MW-hr for the spray dryer scrubber

system. No additional energy or electricity is required for firing compliance coal only. Therefore, the firing of compliance coal without add-on control devices is the preferred option in terms of energy impact.

Comparison of Economic Impacts--Based on the annualized costs presented in Table 5-4 for the lime spray dryer and the wet limestone scrubber systems, the total and incremental cost effectiveness for these add-on control devices are shown in Table 5-5. These effectiveness costs are based on maximum coal firing for the cogeneration facility and 92 percent SO₂ removal using the lime spray dryer scrubber or 95 percent SO₂ removal using the wet lime/limestone scrubbing process.

The total cost effectiveness values are \$2,772 per ton of SO₂ removed for the spray dryer scrubber and \$5,102 per ton of SO₂ removed for the wet limestone scrubber. The incremental cost effectiveness values are \$2,772 per ton of SO₂ removed for the spray dryer scrubber and \$76,570 per ton of SO₂ removed for the wet limestone scrubber. These incremental cost effectiveness values are higher than the levels that FDER and EPA have considered as reasonable for controlling SO₂ emissions (i.e., \$2,000 per ton of SO₂ removed). Therefore, both the wet scrubber and the spray dryer processes are considered as economically infeasible for the project.

The cost effectiveness figures derived above are based on the worst-case condition of firing up to 25 percent coal in a single year (producing 988.2 TPY of SO₂). The actual average case of producing 1,000 TPY SO₂ uncontrolled at Sol-Energy and Flo-Energy is also presented in Table 5-5. Based on the combined Flo-Energy and Sol-Energy annualized costs for the wet scrubbing systems, the total cost effectiveness for installing add-on SO₂ control devices at both facilities is \$6,880 and \$12,633 per ton of SO₂ removal for dry and wet scrubbing, respectively. The incremental cost effectiveness for installing add-on control devices at both facilities are estimated to be \$6,880 and \$190,000 per ton of SO₂ removal for using lime spray dryer scrubbers and wet limestone scrubbers, respectively (refer to Table 5-5). These cost effectiveness values are far greater than the \$2,000 per ton guideline used by FDER and EPA.

Conclusion

The top-down BACT analysis for SO₂ for the proposed boilers firing coal as the auxiliary fuel is summarized in Table 5-5. As discussed above, the analysis has indicated that significant economic, environmental and energy costs are associated with the two alternative scrubber

Table 5-5. Summary Results of the Top-Down BACT Analysis for SO₂ for Sol-Energy Cogeneration Facility.

Control Alternative				Environmental Impacts		Energy Impacts	Economic Impacts			
	Total SO ₂ Emissions (TPY)	Total Emission Reduction (TPY)*	Incremental Emission Reduction (TPY)**	Potential toxic air impact?	Potential adverse enviromental impacts?	Additional Energy Requirements Electricity (MW-hr/yr)	Total Annualized Cost (\$/yr)*	Incremental Annualized Cost (\$/yr)**	Total Cost Effectiveness (\$/ton)*	Incremental Cost Effectiveness (\$/ton)**
<u>Sol-Energy Facility Only- Worst Case Year</u>										
Wet Limestone Scrubber	49.4	938.8	29.6	No	Yes	5,000	\$4,790,000	\$2,270,000	\$5,102	\$76,570
Spray Dry Scrubber	79.1	909.1	909.1	No	Yes	2,400	\$2,520,000	\$2,520,000	\$2,772	\$2,772
Baseline (0.7 Wt% S Coal Uncontrolled)	988.2	--	--	--	--	--	---	---	---	---
<u>Sol-Energy and Flo-Energy Facilities Combined- Average SO₂ Emissions</u>										
Wet Limestone Scrubber	50	950	30	No	Yes	13,000	\$12,030,000	\$5,700,000	\$12,663	\$190,000
Spray Dry Scrubber	80	920	920	No	Yes	6,200	\$6,330,000	\$6,330,000	\$6,880	\$6,880
Baseline (0.7 Wt% S Coal Uncontrolled)	1,000	--	--	--	--	--	---	---	---	---

* Total emission reduction, total annualized cost, and total cost effectiveness are calculated based on similar baseline values (i.e., firing compliance coal only).

** Incremental values are the same as those calculated for total values because of similar reduction efficiency designed for both wet and dry scrubbing systems.

options. The estimated costs for add-on SO₂ controls are unreasonable, particularly considering that it is not intended to burn coal in the cogeneration facility, that coal may never be burned at the facility, and that coal will be burned only if the supply of biomass fuels is not adequate. If add-on controls were required, a very high capital cost would be incurred for equipment that may never be used. No other facility in the United States has been identified where add-on SO₂ controls were required as BACT when the heat input due to fossil fuels was less than 30 percent. In three recent BACT determinations for multifuel stoker boilers, coal is used as supplementary fuel for up to 30 percent of heat input without the use of add-on SO₂ controls. Based on these considerations, using low-sulfur (1.2 lb/MMBtu maximum) coal as the compliance fuel, not to exceed 25 percent of the total annual heat input, represents BACT for the Sol-Energy cogeneration project.

Furthermore, the proposed cogeneration facility will have relatively minor impacts on ambient SO₂ levels. The modeling results show a low SO₂ impact of approximately 7 µg/m³, annual average, on the surrounding area. Per the Palm Beach County zoning conditions, the total combined annual SO₂ emissions from the Sol-Energy and Flo-Energy cogeneration facilities cannot exceed the current SO₂ emissions of approximately 1,000 TPY on a long-term average basis. Thus, the average SO₂ loading to the atmosphere will not increase due to the proposed project. The higher stacks associated with the new cogeneration facility, compared to the shorter stacks of the existing sugar mill facility, will result in a general air quality improvement for SO₂ and all other pollutants.

5.2 BACT DETERMINATION FOR BERYLLIUM

The presence of trace elements in bituminous coal can result in emissions of Be and other trace elements to the atmosphere. The high temperatures in the boiler furnace vaporizes some of these elements. Subsequently, as the temperature of the flue gas drops following the boiler heat recovery system, some of these elements condense onto fine particulate matter or nucleate into new particles. Most of these particulates are then collected in the particulate collection system, if present. For the proposed project, Be will exist as a solid particulate at temperatures existing in the ESP control device (i.e., approximately 350°F). Therefore, the proposed particulate control device will also control Be emissions.

There are no applicable NSPS for Be emissions from utility boilers. Technologies currently available for further reduction of Be and collection of fine particulate matter include ESPs, fabric

filters, and wet scrubbers. Fabric filters and ESPs are the most effective; they reduce most heavy metal emissions, including Be emissions, by 98 percent or greater. Although similar in effectiveness, fabric filters are somewhat superior to ESPs because of their higher degree of fine particle control.

Review of the BACT Clearinghouse information revealed that four wood-fired boilers received BACT determinations for Be emissions. Of these, two were stated to use ESPs as the control device. Be emission limits were approximately $10 \text{ lb}/10^{12} \text{ Btu}$ for both.

For the proposed project, the PM control device will be designed to meet the NSPS level of 0.03 lb/MMBtu for PM emissions. Although the fabric filter would provide somewhat better control of fine particles, the total Be emission rate would be similar to that of the ESP.

Based on these considerations, an emission level for Be based on the ESP technology, which is the selected PM control device for the project, is considered as BACT for the proposed project. Be emissions from the Sol-Energy cogeneration project are estimated to be, based on ESP technology, $0.35 \text{ lb}/10^{12}$ and $5.9 \text{ lb}/10^{12} \text{ Btu}$ for oil firing and coal firing, respectively.

5.3 BACT DETERMINATIONS FOR FLUORIDE AND SULFURIC ACID MIST

Fluoride and sulfuric acid mist are discussed together as acid gases since these compounds can be controlled by similar methods. The emissions of fluoride and sulfuric acid mists are generated from the emissions of fluorine and sulfur trioxide (SO_3) when coal is combusted. Both fluorine and sulfur trioxide can further react with water present in the flue gas to form hydrofluoric and sulfuric acid mists.

The control of acid gas emissions is primarily controlled by removing the precursor pollutants from the flue gas with either wet or dry scrubbing processes. Based on the high cost effectiveness presented for controlling SO_2 emissions from coal-firing, installing a similar system for acid gas removal only would also be economically infeasible. The firing of low sulfur coal acts to control sulfuric acid mist emissions by reducing the amount of sulfur in the stack gases. Therefore, the use of low sulfur coal is considered as BACT for fluorides and sulfuric acid emissions.

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 GENERAL MODELING APPROACH

An air quality analysis for the proposed cogeneration facility was conducted for SO₂, which is the only regulated pollutant subject to PSD review. The purpose of the analysis is to demonstrate compliance with Florida AAQS and, since the Sol-Energy cogeneration facility is an increment consuming facility, demonstrate compliance with the allowable EPA/FDER PSD Class I and Class II increments for SO₂. In addition, an impact analysis for all emitted toxic air pollutants was performed for comparison to FDER's no-threat levels (NTLs).

The general modeling approach followed EPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. For each criteria pollutant that is 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 increase(s) alone will result in predicted impacts in excess of the EPA/FDER significant impact levels. If the project's impacts are above the significant impact levels, a more detailed modeling analysis is performed. Current FDER policies stipulate that the highest annual average and highest short-term (i.e., 24 hours or less) concentrations are to be compared to the applicable significant impact levels. If the screening analysis indicates that maximum predicted concentrations are within 75 percent of the significant impact levels, modeling refinements are performed.

The proposed facility is located in the area of numerous sugar mills, which operate their boilers only part of the year. For modeling purposes, it was necessary to account for the partial year operation of the sugar mill boilers by utilizing two emission inventories, a crop-season inventory and an off-season inventory. The maximum crop season period was assumed to extend from October 1 through April 30. The maximum off-season period was assumed to extend from March 1 through October 31. Since the beginning and ending dates of the crop season vary from year to year, the two seasons were defined such that they overlap several months of the year.

The crop-season inventory included the sugar mill boiler emissions (and/or offsets for PSD purposes, if the boilers were to be shut down). The off-season inventory excluded the emissions and offsets from the sugar mill sources. The two emission inventories are identical in regards to all non-sugar-mill sources. For cases where the maximum impacts were well below the

applicable standards, the analysis was simplified by conservatively assuming that the sugar mill sources operate year round.

6.2 MODEL SELECTION

6.2.1 AAQS/PSD CLASS II

The selection of an appropriate air dispersion model was based on the model's ability to simulate impacts in areas surrounding the Sol-Energy site. Within 50 km of the site, the terrain can be described as simple, i.e., flat to gently rolling. As defined in EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex Short-term (ISCST2, Version 92062) dispersion model (EPA, 1992b) was used to evaluate the pollutant emissions from the proposed facility and other existing major facilities. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISCST2 model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights. The ISCST2 model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on 24 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

Major features of the ISCST2 model are presented in Table 6-1. The ISCST2 model has both rural and urban mode options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the source's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 6-1. Major Features of the ISCST2 Model

-
- Polar or Cartesian coordinate systems for receptor locations
 - Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
 - Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
 - Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
 - Direction-specific building heights and projected widths for all sources for which downwash is considered.
 - Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
 - Separation of multiple-point sources
 - Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
 - Capability of simulating point, line, volume, and area sources
 - Capability to calculate dry deposition
 - Variation of wind speed with height (wind speed-profile exponent law)
 - Concentration estimates for 1-hour to annual average
 - Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
 - Receptors located above local terrain (i.e., "flagpole" receptors)
 - Consideration of time-dependent exponential decay of pollutants
 - The method of Pasquill (1976) to account for buoyancy-induced dispersion
 - A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
 - Procedure for calm-wind processing
 - Wind speeds less than 1 m/s are set to 1 m/s.
-

Source: EPA, 1992b.

In this analysis, the EPA regulatory default options were used to predict all maximum impacts.

The regulatory default options include:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO₂ concentrations in urban areas by using a decay half-life of 4 hours.

6.2.2 PSD CLASS I

For the PSD Class I analysis, the ISCST2 model was used initially as a screening model for estimating impacts on the ENP. EPA and FDER recommend this model as a screening tool for receptors located more than 50 km from a source. For a more refined impact assessment on the ENP, the MESOPUFF II model was utilized. This model is more appropriate for long-range transport applications, where receptors are located more than 50 km from a source. A more complete description of the MESOPUFF II model is provided in Appendix F.

6.3 MODELING ANALYSIS

6.3.1 SIGNIFICANT IMPACT ANALYSIS

The significant impact area for SO₂ was determined based on the proposed facility emissions only (i.e., no credit was taken for shutdown of the existing Osceola boilers). Emission and stack parameters for the proposed cogeneration facility are presented in Table 6-2.

6.3.2 AAQS/PSD MODELING ANALYSIS

A full impact analysis is required for all pollutants subject to PSD that have a significant impact. In general, when 5 years of meteorological data are used, the highest annual and the highest, second-highest (HSH) short-term concentrations are to be compared to the applicable AAQS and allowable PSD increments. The HSH concentration is calculated 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.

Table 6-2. Summary of Osceola Emission, Stack, and Operating Data Used in the Modeling Analysis

ISCST2 Source Identification	Source Description	Coordinates Relative to		Stack Data (m)		Operating Data		Modeled SO ₂ Emissions (g/sec)
		Sol-Energy Boiler Stacks (m)				Temperature (K)	Velocity (m/sec)	
		X	Y	Height	Diameter			
<u>PSD Baseline</u>								
OSBLR1B	Boiler 1	166	-65	22.0	1.52	342	8.98	-5.07
OSBLR2B	Boiler 2	164	-50	22.0	1.52	342	14.22	-16.32
OSBLR3B	Boiler 3	165	-36	22.0	1.93	342	11.23	-7.26
OSBLR4B	Boiler 4	153	-23	22.0	1.83	342	13.35	-13.61
<u>Proposed</u>								
OSCOCRN	Sol-Energy Boilers 1 & 2	0	0	54.9	2.13	449	26.05	139.22

Note: g/sec = grams per second.
K = Kelvin.
lb/MMBtu = pounds per million British thermal units.
m = meters.
m/sec = meters per second.
SO₂ = sulfur dioxide.

This approach is consistent with air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor. To develop the maximum short-term concentrations for the proposed project, the modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. For this study, the only difference between the two phases is the density of the receptor grid spacing employed when predicting concentrations. Concentrations are predicted for the screening phase using a coarse receptor grid and a 5-year meteorological data record.

Refinements of the maximum predicted concentrations are typically performed for the receptors of the screening receptor grid at which the highest and/or HSH concentrations occurred over the 5-year period. Generally, if the maximum concentration from other years in the screening analysis are within 10 percent of the overall maximum concentration, those other concentrations are refined as well. Typically, if the highest and HSH concentrations are in different locations, concentrations in both areas are refined.

Modeling refinements are performed for short-term averaging times by using a denser receptor grid, centered on the screening receptor to be refined. The angular spacing between radials is 2 degrees and the radial distance interval between receptors is 100 m. Annual modeling refinements are developed similarly. If the maximum screening concentration is located on the plant property boundary, additional plant boundary receptors are input, spaced at a 2-degree angular interval and centered on the screening receptor. The domain of the refinement grid extends to all adjacent screening receptors.

The air dispersion model is executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. This approach is used to ensure that a valid HSH concentration is obtained. A more detailed description of the emission inventory, meteorological data, and screening receptor grids used in the analysis, is presented in the following sections.

A complete description of the modeling approach used for application of the MESOPUFF II model is contained in Appendix F.

6.4 METEOROLOGICAL DATA

Meteorological data used in the ISCST2 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) stations at West Palm Beach. The 5-year period of meteorological data was from 1982 through 1986. The NWS station at West Palm Beach, located approximately 60 km east of the Sol-Energy site, was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the plant site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated with the radiosonde data using the Holzworth approach (1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions were classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed by using the EPA RAMMET meteorological preprocessor program.

Meteorological data used in the MESOPUFF II modeling analysis are discussed in Appendix F.

6.5 EMISSION INVENTORY

6.5.1 OSCEOLA FARMS AND SOL-ENERGY

Stack and operating parameters and emission rates for the Osceola Farms PSD baseline sources are presented in Table 6-2. Parameters for the proposed cogeneration facility are also shown. The current mill configuration is somewhat different than in the PSD baseline period (i.e., 1975). Boilers 5 and 6 have been added at the mill, Boiler No. 1 has been removed, and the other boilers have undergone stack height increases.

6.5.2 OTHER AIR EMISSION SOURCES

The proposed cogeneration facility produces a significant impact for SO₂. Therefore, a detailed impact analysis has been performed for this pollutant. Sol-Energy's SIA was determined to be 70 km. An inventory of all facilities used in the modeling analyses is presented in Table 6-3. This list was developed from the 1991 Air Pollutant Information System (APIS) reports provided to KBN by FDER, supplemented by existing source permits and other recent modeling analyses performed in this area. This list includes all SO₂ sources located within 70 km of the Sol-Energy site and emitting greater than 25 TPY. Also included are six sources located outside the SIA, but which may have a significant impact on the SIA or are PSD increment consuming sources. Beyond the SIA, sources emitting less than 100 TPY were not included in the analysis.

A summary of all source data used in the modeling analysis, including which sources are designated as PSD (increment consuming or expanding) sources, is presented in Table 6-4. Table 6-4 details which sources were used in the AAQS, PSD Class II, and PSD Class I modeling analyses. Included in this list is the proposed Flo-Energy (Okeelanta) cogeneration facility, which will replace the existing Okeelanta sugar mill. Therefore, the existing Okeelanta sources are not included in the table. In general, stack, SO₂ emissions, and operating information were obtained from APIS for the year 1991. The emission data for Tarmac, Florida Power & Light Company (FPL) plants, and sugar mill sources within the SIA were available from current air operating or construction permits. The stack and operating parameters for these sources were obtained from prior PSD applications (KBN, 1990a and b). For the U.S. Sugar Corporation Bryant mill, maximum SO₂ emissions were calculated based on permit information and the sulfur content of fuels utilized. Calculations are provided in Appendix G.

Sources within one facility were sometimes combined if their stack heights were the same and the sources had similar operating parameters. Some small sources were sometimes combined with larger sources within the same facility (emissions were added to the larger source).

For most facilities, 3-hour worst-case emission rates were used for all averaging time analyses. For 24-hour and annual averaging times, 24-hour emission rates were used in place of 3-hour emission rates for a few sources, where available. These are noted in the footnote at the bottom of Table 6-4.

Table 6-3. Non-Osceola Sources (>25 TPY) Used in the Modeling Inventories

APIS Number	Facility	County	UTM Coordinates (km)		Location Relative To Proposed Site (km)		Distance From Proposed Site (km)	Direction From Proposed Site (degrees)	Maximum SO ₂ ^a Emissions (TPY)
			East	North	X	Y			
52FTM500061	U.S. Sugar -Bryant	Palm Beach	538.8	2968.1	-5.4	0.1	5.4	271	2,364
52FTM500026	Sugar Cane Growers	Palm Beach	534.9	2953.3	-9.3	-14.7	17.4	212	4,269
50PMB500021	Pratt & Whitney	Palm Beach	559.2	2978.3	15.0	10.3	18.2	56	3,386
NA	Bechtel Indiantown	Martin	545.6	2991.5	1.4	23.5	23.5	3	2,629
52FTM500016	Atlantic Sugar	Palm Beach	552.9	2945.2	8.7	-22.8	24.4	159	1,484
50PMB500086	Glades Correctional Institute	Palm Beach	523.4	2955.2	-20.8	-12.8	24.4	238	485
50WPB430001	FPL -Martin	Martin	543.1	2992.9	-1.1	24.9	24.9	357	93,788
NA	Flo-Energy Boilers 1, 2 & 3	Palm Beach	525.0	2937.4	-19.2	-286	34.4	214	1,596
52FTM260001	Evercane Sugar	Hendry	509.6	2954.2	-34.6	-13.8	37.3	248	1,408
50WPB430007	Dickerson	Martin	569.5	2995.9	25.3	27.9	37.7	42	58
52FTM260003	US Sugar Clewiston	Hendry	506.1	2956.9	-38.1	-11.1	39.7	254	5,353
69 NA	Palm Beach Resource Recovery	Palm Beach	585.8	2960.2	41.6	-7.8	42.3	101	1,533
50WPB430021	Stuart Contracting	Martin	575.2	3006.8	31.0	38.8	49.7	39	100
50PMB500042	FPL -Riviera Beach	Palm Beach	594.2	2960.6	50.0	-7.4	50.5	98	77,815
50PMB500045	Lake Worth Utilities	Palm Beach	592.8	2943.7	48.6	-24.3	54.3	117	2,302
52FTM260015	Southern Gardens	Hendry	487.6	2957.6	-56.6	-10.4	57.5	260	173
50WPB560003	Fort Pierce Utilities	St. Lucie	566.8	3036.3	22.6	68.3	71.9	18	2,708
50WPB062120	North Broward Res. Rec.	Broward	583.6	2907.6	39.4	-60.4	72.1	147	896
30ORL310029	Vero Beach Power	St. Lucie	567.1	3056.5	22.9	88.5	91.4	15	18,496
50WPB062119	South Broward Res. Rec.	Broward	579.6	2883.3	35.4	-84.7	91.8	157	1,318
50BRO060037	FPL -Fort Lauderdale	Broward	580.1	2883.3	35.9	-84.7	92.0	157	65,964
50BRO060036	FPL -Port Everglades	Broward	587.4	2885.3	43.2	-82.7	93.3	152	76,239

^a Indicates facilities with sources that only operate part of the year; October 1 through April 30.
PSD indicates facilities with PSD increment consuming and/or expanding sources.

Table 6-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 1 of 3)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO ₂ 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
52FTM500016	Atlantic Sugar									
	Unit 1 ^a	18.9	1.92	346	12.7	17.24		Yes	No	No
	Unit 2 ^a	18.9	1.92	342	10.9	22.50		Yes	No	No
	Unit 3 ^a	21.9	1.83	341	17.5	16.88		Yes	No	No
	Unit 4 ^a	18.3	1.83	344	15	16.88		Yes	No	No
	Unit 5 ^a PSD	27.4	1.68	339	15.7	11.80	CON	Yes	Yes	Yes
50WPB43????	Bechtel Indiantown PSD	150.9	4.88	333.2	30.5	75.64	CON	Yes	Yes	Yes
50DAD130348	Dade County RRF PSD									
	Units 1&2 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 3&4 proposed mod.	64.9	3.66	405.4	15.86	12.30	CON	No	No	Yes
	Units 5&6 proposed	76.2	4.2	399.8	15.74	17.20	CON	No	No	Yes
50WPB430007	Dickerson	12.8	1.83	321.9	9.75	1.69		Yes	No	No
52FTM260001	Evercane Sugar ^a	21.9	1.1	477	10.1	11.80		Yes	No	No
	Fort Pierce	45.7	4.88	411.0	10.97	77.9		Yes	No	No
50BRO060037	FPL - Lauderdale									
	CTs 1-4 PSD	45.7	4.88	411	10.97	271.10	CON	Yes	Yes	Yes
	4&5 PSD Baseline	46	4.27	422	14.63	457.00	EXP	No	Yes	Yes
50WPB430001	FPL Martin									
	Units 1&2	152.1	7.99	420.9	21.03	1743.79		Yes	No	No
	Aux Blr PSD	18.3	1.1	535.4	15.24	12.90	CON	Yes	Yes	Yes
	Diesl Gens PSD	7.6	0.3	785.9	39.62	0.51	CON	Yes	Yes	Yes
	Units 3&4 PSD	64.9	6.1	410.9	18.9	470.40	CON	Yes	Yes	Yes
50BRO060036	FPL - Port Everglades									
	GT 1-2	15.5	5.49	733	21.34	488.39		Yes	No	No
	Units 1&2	104.9	4.27	416	18.59	637.54		Yes	No	No
	Units 3&4	104.5	5.52	108	19.2	1067.16		Yes	No	No
50PMB500042	FPL - Riviera Beach									
	Unit 2	45.7	4.57	430.2	7.62	124.86		Yes	No	No
	3&4	90.8	4.88	408	18.9	846.33		Yes	No	No
50PMB500086	Glades Corr Institute	9.8	0.4	389	11.28	2.82		Yes	No	No
50PMB500045	Lake Worth									
	Units 1&2	18.23	1.52	434.1	6.19	72.58		Yes	No	No
	Units 3&4	38.1	2.29	408	9.69	237.90		Yes	No	No
	Unit 5	22.9	0.95	450.2	18.29	11.59		Yes	No	No
NA	Lee County RRF PSD	83.8	1.88	388.5	19.81	14.00	CON	No	No	Yes
NA	North Broward RRF PSD	58.5	3.96	381	18.01	35.40	CON	Yes	Yes	Yes

Table 6-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 2 of 3)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO ₂ 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
	Okeelanta									
	Boiler 4 PSD Baseline	22.9	2.29	333	7.36	-10.95	EXP	No	No	Yes
	Boiler 5 PSD Baseline	22.9	2.29	333	12.07	-15.64	EXP	No	No	Yes
	Boiler 6 PSD Baseline	22.9	2.29	334	8.74	-15.64	EXP	No	No	Yes
	Boiler 10 PSD Baseline	22.9	2.29	334	10.35	-17.15	EXP	No	No	Yes
	Boiler 11 PSD Baseline	22.9	2.29	342	9.89	-16.79	EXP	No	No	Yes
	Boiler 12 PSD Baseline	22.9	2.29	330	8.16	-20.58	EXP	No	No	Yes
	Boiler 14 PSD Baseline	22.9	2.29	333	8.28	-20.03	EXP	No	No	Yes
	Boiler 15 PSD Baseline	22.9	2.29	332	10.23	-16.79	EXP	No	No	Yes
	Flo-Energy Boilers 1 and 2	60.66	2.44	450	21.25	222.26	CON	Yes	Yes	Yes
	Vero 1	60.96	1.83	451	6.4	65.8		Yes	No	No
	Vero 2	60.96	1.71	451	25.3	84.4		Yes	No	No
	Vero 3	60.96	2.13	485	10.4	144.5		Yes	No	No
	Vero 4	60.96	2.13	463	15.5	69.0		Yes	No	No
50WPB500234	Palm Beach RRF 1&2 PSD	76.2	2.04	505.2	24.9	85.05	CON	Yes	Yes	No
50PMB500021	Pratt & Whitney									
	ACHR-1	1.8	0.91	500	40.23	16.02		Yes	No	No
	ACHR-2	15.2	0.91	500	40.23	47.92		Yes	No	No
	ACHR-3	4.6	3.38	700	13.44	23.46		Yes	No	No
	BO-12	4.6	0.76	500	6.92	9.08		Yes	No	No
	LI-1 MW	8.2	0.67	2000	8.35	6.18		Yes	No	No
NA	South Broward RRF PSD	59.4	3.96	381	18.01	37.91	CON	Yes	Yes	Yes
52FTM260015	Southern Gardens PSD	22	0.64	479.8	17.48	4.99	CON	Yes	Yes	Yes
	Stuart Contracting	11.9	1.22	421.9	24.08	1.99		Yes	No	No
52FTM500026	Sugar Cane Growers									
	Unit 3 ^a	24.4	1.6	344	15.6	4.40		Yes	No	No
	Unit 4 PSD ^a	33.5	1.63	344	10.6	24.20	CON	Yes	Yes	Yes
	Unit 4 PSD Baseline ^a	25.9	2.82	344	10.6	-24.20	EXP	No	Yes	Yes
	Unit 5 ^a	24.4	1.4	344	15.2	16.20		Yes	No	No
	Unit 8 PSD ^a	47.2	3.05	344	10.6	26.70	CON	Yes	Yes	Yes
	Unit 1&2 ^a	24.4	1.4	344	11.4	24.20		Yes	No	No
	Unit 6&7 ^a	12.2	2.13	606	11.2	51.00		Yes	No	No
50DAD130020	Tarmac									
	Kiln 2 PSD Baseline	61	2.44	465	12.84	-5.71	EXP	No	No	Yes
	Kiln 3 PSD Baseline	61	4.57	472	10.78	-2.76	EXP	No	No	Yes
	Kiln 2 PSD	61	2.44	422	9.1	24.50	CON	No	No	Yes
	Kiln 3 PSD	61	4.57	450	11.04	51.40	CON	No	No	Yes
52FTM260003	US Sugar Clewiston									
	Unit 3 ^a	27.4	2.29	340	14.54	28.16 ^b		Yes	No	No
	Unit 4 PSD ^a	45.7	2.51	334	19.66	16.26 ^b	CON	Yes	Yes	Yes
	Units 1&2 ^a	22.9	1.86	339	35.54	95.22 ^b		Yes	No	No
	Units 5&6 ^a	19.8	1.83	340	9.78	4.48		Yes	No	No

Table 6-4. Summary of Non-Osceola Source Data Used in Modeling Analysis (Page 3 of 3)

APIS Number	Facility	Stack		Temp (K)	Velocity (m/s)	SO ₂ 3-Hour Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in		
		Height (m)	Diameter (m)					AAQS	Class II	Class I
52FTM500061	US Sugar-Bryant Unit 5 PSD ^a Unit 1,2&3 ^a	42.7	2.9	345	11.49	68.07 ^b	CON	Yes	Yes	Yes
		19.8	1.64	342	36.4	174.36 ^b		Yes	No	No

^a These sources operate only during the crop season, October 1 through April 30.

^b The following sources were modeled under 24 hour and annual averaging times with the following emission rates (g/s):

US Sugar Clewiston Unit 3:	22.99	US Sugar Bryant Unit 5 PSD:	67.38
US Sugar Clewiston Unit 4:	14.78	US Sugar Bryant Unit 1,2&3:	63.66
US Sugar Clewiston Unit 1&2:	80.68		

Three separate modeling emission inventories were prepared for the modeling effort.

1. For the AAQS analysis, all sources listed in Table 6-4 and located within 70 km of the proposed site, and major utilities located within 100 km of the proposed site were used.
2. The Class II inventory included PSD increment consuming and/or expanding sources within 70 km and major utility PSD increment consuming and/or expanding sources within 100 km. To be conservative and to simplify the screening modeling analysis, increment expanding shutdowns of sugar mill boilers (i.e., at Okeelanta and Osceola Farms) were not modeled. In addition, increment consuming sugar mill boilers (i.e., at Atlantic Sugar, Sugar Cane Growers, and U.S. Sugar Clewiston and Bryant) were assumed to operate year around. However, for the 24-hour averaging time in the refined analysis, the modeling analysis was separated into the crop and off-season time periods, with the sugar mill sources reflected appropriately in the inventory.
3. An emission inventory for modeling SO₂ at the Everglades National Park, a PSD Class I area, was developed to include all PSD sources within 100 km from the Everglades National Park. The inventory included regional resource recovery facilities (e.g, Lee, Dade, and Broward counties), future expansion at FPL Martin power facility in Martin County, the proposed Flo-Energy (Okeelanta) cogeneration facility, and all increment-consuming sugar mill sources. Offsets from Okeelanta and Osceola were applied only during the crop season time period. The PSD Class I inventory was therefore subdivided into two inventories, crop-season and off-season. As discussed previously, two seasons were modeled with overlapping periods. No offsets were applied for the non-crop season. The two separate analyses were compared after screening results were complete. Highest impacts occurred during the non-crop season. Refinements and reported maximums are from this inventory.

6.6 RECEPTOR LOCATIONS

6.6.1 SIGNIFICANT IMPACT ANALYSIS

For short and long term averaging periods, concentrations were predicted at 288 receptors located in a radial grid centered on the proposed stacks for the new cogeneration units. Receptors were located in "rings," with 36 receptors per ring spaced at 10-degree intervals at distances of 7, 11, 14, 20, 30, 40, 50, 60, and 70 km.

6.6.2 AAQS IMPACT ASSESSMENTS

For the AAQS analysis, both near- and far-field receptor grids were used. Osceola's and Sol-Energy's nearest property boundary is located approximately 1.0 km from the stack locations. The near-field screening grids included 36 receptors for each 10 degree sector located on the following rings: at the plant property; 2, 4, and 6 km in directions outside plant property (distance to property boundary varies greatly by sector); and 8, 11, 14, 17, and 20 km. The far-field screening grid included six rings of receptors at distances of 25, 30, 40, 50, 60, and 70 km.

In addition, a detailed screening grid was utilized in the AAQS analysis. This grid was centered on the near-field screening receptor at 270°, 6.0 km, which is near the U.S. Sugar Corporation's Bryant mill.

To the east of the proposed cogeneration facility, the Osceola site surrounds a parcel of land that is not owned or leased by either Sol-Energy or Osceola Farms. For the analysis, this land was considered as accessible to the public (i.e., as ambient air).

The nearest property boundary receptors used for the screening modeling are presented in Table 6-5. All receptor locations are relative to the proposed cogeneration facility stack location (co-located stacks).

6.6.3 PSD CLASS II IMPACT ASSESSMENTS

To cover the spatial extent of Sol-Energy's significant impact area for SO₂ (70 km), near-field and far-field receptor grids were used for the PSD Class II screening analyses. The Class II screening grids were the same as the AAQS screening grids.

6.6.4 CLASS I IMPACT ASSESSMENT

The Everglades National Park is a PSD Class I area that is located beyond 100 km of the Sol-Energy plant site. Through passage of the Clean Air Act of 1990, the park's eastern edge has been expanded farther to the east. The northeastern corner of the expanded Class I area is approximately 120 km south of the Sol-Energy site (see Figure 6-1). In the screening analysis, Everglades National Park is represented by 51 discrete receptors, including 47 receptors covering the eastern and northern boundaries of the park from the Florida Keys to the Gulf of Mexico and 4 receptors inside the northeast corner of Everglades National Park. The Universal Transverse Mercator (UTM) coordinates of these Class I receptors are listed in Table 6-6. Refined modeling

Table 6-5. Property Boundary Receptors Used in the Modeling Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	3033	190	1040
20	3179	200	1090
30	3449	210	1183
40	3899	220	1337
50	4647	230	1592
60	2252	240	1408
70	2076	250	1297
80	1981	260	1238
90	1951	270	1219
100	2352	280	1238
110	2465	290	1297
120	2048	300	1408
130	1631	310	1592
140	1944	320	1897
150	2041	330	2438
160	1881	340	3179
170	1040	350	3033
180	1024	360	2987

Note: Distances are relative to Sol-Energy proposed stack location.

Table 6-6. Everglades National Park Receptors Used for the Class I Screening Analyses

Receptor	UTM Coordinates (km)		Receptor	UTM Coordinates (km)	
	East	North		East	North
1	557.0	2789.0	27	540.0	2848.6
2	556.6	2792.0	28	535.0	2848.6
3	556.0	2796.0	29	530.0	2848.6
4	553.0	2796.5	30	525.0	2848.6
5	548.0	2796.5	31	520.0	2848.6
6	542.7	2796.5	32	515.0	2848.6
7	542.7	2800.0	33	515.0	2843.0
8	542.7	2805.0	34	515.0	2838.0
9	542.7	2810.0	35	515.0	2833.0
10	542.0	2811.0	36	510.0	2833.0
11	541.3	2814.0	37	505.0	2833.0
12	542.7	2816.0	38	500.0	2833.0
13	544.1	2820.0	39	495.0	2833.0
14	543.5	2824.6	40	494.5	2837.0
15	545.0	2829.0	41	491.5	2841.0
16	545.7	2832.2	42	488.5	2845.5
17	546.2	2835.7	43	483.0	2848.5
18	548.6	2837.5	44	480.0	2852.5
19	550.3	2839.0	45	475.0	2854.0
20	445.0	2839.0	46	473.5	2857.0
21	440.0	2839.0	47	473.5	2860.0
22	550.5	2844.0	48	469.0	2860.0
23	545.0	2844.0	49	464.0	2860.0
24	540.0	2844.0	50	459.5	2864.0
25	550.3	2848.6	51	454.0	2864.0
26	545.0	2848.6			

Note: km = kilometers.
UTM = Universal Transverse Mercator.

was performed for the Class I area by using a receptor spacing of 1.0 km centered on the receptor of interest extending to the adjacent receptors.

6.7 BUILDING DOWNWASH CONSIDERATIONS

The procedures used for addressing the effects of building downwash are those recommended in the ISC2 Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than $H_b + 0.5 L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used.

The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than $H_b + 0.5 L_b$ but less than GEP, the Huber and Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. For both methods the direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

The existing Osceola and proposed Sol-Energy stacks have heights that are below that required to completely avoid building downwash effects. Therefore, the modeling analysis addresses the effects of aerodynamic downwash for these stacks. To determine the potential for downwash to occur, the following buildings were analyzed from a layout plan of the site.

<u>Building</u>	<u>Height (m)</u>	<u>Length (m)</u>	<u>Width (m)</u>
Existing Boiler Building	21.34	92.0	70.0
Proposed Boilers 1 & 2	37.64	42.0	23.0

The potential for downwash was determined for each 1 degree within each 10-degree direction sector. For each direction, a building structure was determined to be within the zone of influence of a stack if the stack is within $5L_b$ downwind off the building, $2L_b$ upwind of the building, or $0.5L_b$ crosswind of the building. Based on this analysis, direction-specific building heights and

widths were developed for each 10-degree direction sector and included for both existing and proposed stacks on the site.

6.8 BACKGROUND CONCENTRATIONS

To estimate total air quality concentrations, a background concentration must be added to the modeling results. The background concentration is considered to be the air quality concentration contributed by sources not included in the modeling evaluation.

In order to develop a conservative estimate of the SO₂ background with the existing Osceola boilers shut down, the second highest 3-hour and 24-hour and highest annual average SO₂ concentrations measured at the Belle Glade monitor during the period 1989-1991 were used. Based on this analysis, the background SO₂ concentrations were determined to be 53 and 21 µg/m³ for the 3- and 24-hour averaging periods, respectively, and 8 µg/m³ for the annual averaging period. These background levels were added to model-predicted concentrations to estimate total air quality levels for comparison to AAQS.

6.9 AIR QUALITY MODELING RESULTS

6.9.1 SIGNIFICANT IMPACT ANALYSIS

The maximum air quality impacts from the proposed Sol-Energy facility only are presented in Table 6-7. As shown, the facility's maximum annual, 24-hour, and 3-hour predicted SO₂ concentrations are 7.0, 106, and 220 µg/m³, respectively. These all occur at the plant property boundary. These maximum impacts are above the respective SO₂ significant impact levels of 1, 5, and 25 µg/m³. Therefore, a full impact assessment was performed for this pollutant to demonstrate compliance with allowable PSD increments and AAQS. It was determined that the distance of the total facility's significant impact for SO₂ is 70 km, based on the maximum 3-hour worst-case coal-burning emissions.

6.9.2 AAQS ANALYSIS

The results of the SO₂ screening modeling analyses for the near- and far-field receptor grid are presented in Tables 6-8 and 6-9 respectively. Results from a more detailed screening grid, centered about receptor location 270°, 6000 m, are presented in Table 6-10. This grid was analyzed because the screening analysis indicated maximum impacts for all averaging times may be located in this area. The maximum annual, 24-hour, and 3-hour impacts from the screening analysis are 32, 205, and 1,155 µg/m³, respectively. For all averaging times, maximum

Table 6-7. Maximum Predicted SO₂ Concentrations for the Proposed Facility Only

Averaging Time	Concentration ^a ($\mu\text{g}/\text{m}^3$)	Receptor Location ^b		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	7.0	320.	1897.	82-----
	5.3	320.	1897.	83-----
	5.2	320.	1897.	84-----
	5.0	320.	1897.	85-----
	4.3	270.	2000.	86-----
24-Hour Highest	106	220.	1337.	82110724
	84	320.	1897.	83020124
	79	180.	2000.	84053124
	93	230.	1592.	85091524
	67	220.	1337.	86101924
24-Hour HSH ^c	82	220.	2000.	82110924
	69	320.	1897.	83040724
	65	220.	1337.	84100924
	69	230.	1592.	85100824
	55	220.	1337.	86082324
3-Hour Highest	220	220.	1337.	82110706
	207	170.	1040.	83123118
	242	180.	1024.	84053118
	225	210.	1183.	85051515
	208	320.	1897.	86121103
3-Hour HSH ^c	186	230.	1592.	82101918
	170	220.	1337.	83092509
	196	180.	1024.	84090812
	171	230.	1592.	85111812
	181	220.	1337.	86101824

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a Maximum concentrations indicated are for the proposed facility with no offsets.

^b All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^c Highest, second-highest (HSH) concentrations shown.

Table 6-8. Maximum Predicted SO₂ Concentrations for the AAQS Screening Analysis, Near-Field Receptors

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	27	220.	17000.	82-----
	22	220.	17000.	83-----
	24	270.	6000.	84-----
	23	270.	8000.	85-----
	25	270.	6000.	86-----
24-Hour ^b	132	220.	17000.	82073024
	146	220.	17000.	83040724
	169	210.	17000.	84022824
	133	280.	6000.	85082424
	138	270.	8000.	86110724
3-Hour ^b	725	270.	6000.	82070612
	858	280.	6000.	83101312
	962	270.	6000.	84040212
	935	270.	6000.	85090812
	937	270.	6000.	86100112

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^b All short-term concentrations indicate highest, second-highest concentrations.

Table 6-9. Maximum Predicted SO₂ Concentrations for the AAQS Screening Analysis, Far-Field Receptors

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	22	120.	50000.	82-----
	18	120.	50000.	83-----
	24	120.	50000.	84-----
	22	120.	50000.	85-----
	22	120.	50000.	86-----
24-Hour ^b	146	120.	50000.	82100324
	153	160.	25000.	83061624
	161	160.	25000.	84090624
	133	120.	50000.	85111424
	132	160.	25000.	86102024
3-Hour ^b	422	160.	25000.	82112218
	466	160.	25000.	83082418
	587	160.	25000.	84011515
	460	160.	25000.	85092515
	421	160.	25000.	86101718

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^b All short-term concentrations indicate highest, second-highest concentrations.

Table 6-10. Maximum Predicted SO₂ Concentrations for the AAQS Detailed Screening Analysis Grid^a

Averaging Time	Concentration (µg/m ³)	Receptor Location ^b		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	32	276.	6200.	82-----
	27	276.	6200.	83-----
	31	270.	6500.	84-----
	29	270.	6500.	85-----
	31	270.	6500.	86-----
24-Hour ^c	169	276.	6200.	82070724
	164	278.	6200.	83072024
	205	270.	6500.	84121524
	165	270.	6500.	85041224
	179	270.	6900.	86110724
3-Hour ^c	1055	272.	6200.	82070515
	1037	276.	5900.	83072012
	1013	276.	5900.	84073112
	1054	274.	6200.	85042615
	983	274.	5900.	86051215

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a Centered on screening grid receptor location (6000 m, 270°).

^b All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^c All short-term concentrations indicate highest, second-highest concentrations.

concentrations were predicted approximately 6.0 km from the Sol-Energy site. The maximum concentrations were caused primarily by other modeled sources. The results indicate that the maximum SO₂ concentrations will not exceed SO₂ AAQS at any location in the vicinity of the Sol-Energy plant.

Based on the screening analysis, refinements were performed for all averaging periods. The refined concentrations, including background SO₂ levels, are presented in Table 6-11. The predicted maximum annual, 24-hour, and 3-hour concentrations are 46, 227, and 1,108 $\mu\text{g}/\text{m}^3$, respectively. These predicted maximum impacts are due primarily to sources other than Sol-Energy, and are located approximately 6 km from the Sol-Energy site. This analysis indicates that AAQS will be met at locations within the SIA. Source contributions for refined maximums are detailed in Appendix E.

6.9.3 PSD CLASS II ANALYSIS

The results of the PSD Class II screening analysis for the near-field and far-field receptor grids are presented in Tables 6-12 and 6-13, respectively. Based on the screening results, refined modeling analyses were performed for each averaging time. For the refined analysis for the 24-hour averaging time, the crop and off-season time periods were modeled separately, with the sugar mill sources operating only during the crop season period. Source contributions for refined maximums are detailed in Appendix E. The refined results, summarized in Table 6-14, indicate that the maximum SO₂ PSD Class II increment consumption will not exceed the allowable PSD increments. The maximum annual, 24-hour, and 3-hour predicted increment consumption of 10.9, 76, and 216 $\mu\text{g}/\text{m}^3$, respectively, are below the allowable PSD Class II increments of 20, 91, and 512 $\mu\text{g}/\text{m}^3$. The maximum annual increment consumption values are due primarily to sources other than Sol-Energy, and occur 7 km from the Sol-Energy site. The maximum 24- and 3-hour increment consumption values are due primarily to the proposed cogeneration facility and occur at or just beyond the property boundary.

6.9.4 PSD CLASS I ANALYSIS

The SO₂ PSD Class I screening grid modeling results using the ISCST2 model, are presented in Tables 6-15 and 6-16. The refined modeling results are presented in Table 6-17. The refined results indicate that the maximum annual, 24-hour, and 3-hour PSD increment consumed at the expanded Everglades National Park are 0.7, 4.21, and 22.8 $\mu\text{g}/\text{m}^3$, respectively. Source

Table 6-11. Maximum Predicted SO₂ Concentrations as Compared With AAQS - Refined Analysis

Averaging Time	Concentration ($\mu\text{g}/\text{m}^3$)			Receptor Locations ^a		Period Ending (YYMMDDHH)	Florida AAQS ($\mu\text{g}/\text{m}^3$)
	Total	Modeled	Background	Direction (degrees)	Distance (m)		
Annual	46	38	8	277	6,200	82-----	60
	39	31	8	270	6,400	84-----	
	41	33	8	271	6,400	86-----	
24-Hour ^b	227	206	21	270	6,600	84121524	260
3-Hour ^b	1,108	1,055	53	272	6,200	82070515	1,300
	1,107	1,054	53	274	6,200	85042615	

Note: YY = Year, MM = Month, DD = Day, HH = Hour

^a Receptors locations are relative to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.^b All short-term concentrations are highest, second-highest concentrations.

Table 6-12. Maximum Predicted SO₂ Concentrations for the PSD Class II Screening Analysis, Near-Field Receptors

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	8.4	320.	1897.	82-----
	7.3	320.	1897.	83-----
	8.7	270.	8000.	84-----
	8.0	270.	8000.	85-----
	8.9	270.	8000.	86-----
24-Hour ^b	82	220.	2000.	82110924
	69	320.	1897.	83040724
	65	220.	1337.	84100924
	69	230.	1592.	85100824
	66	270.	8000.	86110724
3-Hour ^b	186	230.	1592.	82101918
	170	220.	1337.	83092509
	203	180.	1024.	84090812
	171	230.	1592.	85111812
	181	220.	1337.	86101824

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^b All short-term concentrations indicate highest, second-highest concentrations.

Table 6-13. Maximum Predicted SO₂ Concentrations for the PSD Class II Screening Analysis, Far-Field Receptors

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)
		Direction (degrees)	Distance (m)	
Annual	5.5	350.	25000.	82-----
	4.5	350.	25000.	83-----
	5.2	350.	25000.	84-----
	5.4	350.	25000.	85-----
	5.7	350.	25000.	86-----
24-Hour ^b	28	350.	25000.	82050224
	29	350.	25000.	83043024
	30	350.	25000.	84081424
	29	350.	25000.	85102124
	24	340.	25000.	86032624
3-Hour ^b	79	350.	25000.	82112412
	90	350.	25000.	83012012
	98	350.	25000.	84070512
	100	350.	25000.	85090812
	86	350.	25000.	86072415

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are reported with respect to the midpoint of the proposed Sol-Energy Cogeneration facility stacks.

^b All short-term concentrations indicate highest, second-highest concentrations.

Table 6-14. Maximum Predicted SO₂ Concentrations as Compared with PSD Class II Increments - Refined Analysis

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)	Allowable Increment (µg/m ³)
		Direction (degrees)	Distance (m)		
Annual	10.5	269	6800	84-----	20
	10.9	271	6800	86-----	
24-Hour ^b	33 ^c	224.	2300.	82110924	91
	58 ^d	320.	2100.	83030624	
	67	222.	1378.	84100924	
	76	232.	1600.	85100824	
	58 ^d	220.	1337.	86082324	
3-Hour ^b	216	182.	1200.	84090812	512

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are with respect to proposed Sol-Energy Cogeneration facility's co-located stack location.

^b All short-term concentrations are highest, second-highest concentrations.

^c Due to application of sugar mill offsets in crop season, the screening maximum of 82 µg/m³ was reduced to 33 µg/m³.

^d After the application of offsets during the crop season, the HSH screening concentration became the highest concentration. The day provided is the new HSH day.

Table 6-15. Maximum Predicted SO₂ Concentrations for the PSD Class I Screening Analysis, Off-Season^a

Averaging Time	Concentration (μg/m ³)	Receptor Location ^b		Period Ending (YYMMDDHH)
		UTM-E (m)	UTM-N (m)	
Annual	0.54	550300.	2848600.	82----
	0.64	550300.	2848600.	83----
	0.52	550300.	2848600.	84----
	0.47	545000.	2848600.	85----
	0.48	550300.	2848600.	86----
24-Hour ^c	4.01	500300.	2848600.	82083024
	5.42	550300.	2839000.	83081724
	3.79	530000.	2848600.	84053124
	3.75	545000.	2848600.	85102524
	3.20	550300.	2848600.	86033024
3-Hour ^c	18.4	550000.	2832500.	82071621
	19.0	545000.	2844000.	83061706
	17.4	540000.	2839000.	84041121
	18.4	545000.	2844000.	85032521
	16.8	464000.	2860000.	86103106

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a Maximum period during which sugar mills are not operating, which extends from 3/1 through 10/31.

^b All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

^c All short-term concentrations indicate highest, second-highest concentrations.

Table 6-16. Maximum Predicted SO₂ Concentrations for the PSD Class I Screening Analysis, Crop Season^a

Averaging Time	Concentration (µg/m ³)	Receptor Location ^b		Period Ending (YYMMDDHH)
		UTM-E (m)	UTM-N (m)	
Annual	0.50	550300	2848600	82-----
	0.42	540000	2848600	83-----
	0.47	545000	2848600	84-----
	0.41	545000	2848600	85-----
	0.37	545000	2848600	86-----
24-Hour ^c	3.33	550300	2848600	82112324
	3.93	535000	2848600	83012424
	3.17	540000	2848600	84021524
	3.29	545000	2848600	85022024
	3.00	545000	2848600	86010724
3-Hour ^c	15.6	545000	2848600	82112318
	16.3	542700	2816000	83121924
	15.8	540000	2848600	84030409
	17.5	535000	2848600	85120224
	15.2	530000	2848600	86102806

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a Maximum period during which sugar mills are operating, which extends from 10/1 through 4/30.

^b All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

^c All short-term concentrations indicate highest, second-highest concentrations.

Table 6-17. Maximum Predicted SO₂ Concentrations as Compared with PSD Class I Increments - Refined Analysis

Averaging Time	Concentration (µg/m ³)	Receptor Location ^a		Period Ending (YYMMDDHH)	Allowable Increment (µg/m ³)
		UTM-E (m)	UTM-N (m)		
Annual	0.7	549000.	2848600.	83-----	2
24-Hour ^b	4.21 ^c	550300.	2839000.	83081724	5
3-Hour ^b	22.8	497000.	2830500.	82071621	25
	21.4	547000.	2848600.	83081603	
	19.9	546000.	2845000.	85041721	

Note: YY=Year, MM=Month, DD=Day, HH=Hour

^a All receptor coordinates are reported in Universal Transverse Mercator (UTM) coordinates.

^b All short-term concentrations are highest, second-highest concentrations.

^c Obtained using MESOPUFF II model for refined analysis (see Appendix F).

contributions for refined maximums are detailed in Appendix E. These impacts are below the allowable PSD Class I increments of 2 and 25 $\mu\text{g}/\text{m}^3$ for the annual and 3-hour averaging times, respectively. The proposed facility with other increment consuming sources will therefore meet the allowable PSD increments in the Class I area.

It is noted that the screening analysis with ISCST2 model indicates that the 24-hour Class I increment of 5 $\mu\text{g}/\text{m}^3$ may be exceeded in the Class I area, but only during three 24-hour periods in the 5-year meteorological database (all occurring in 1983). Analysis of the source contributions to these maximums show that the proposed Sol-Energy cogeneration project contributes from 1.33 to 1.97 $\mu\text{g}/\text{m}^3$ to the predicted high concentrations, which are greater than the National Park Service's recommended 24-hour SO_2 Class I significance level of 0.07 $\mu\text{g}/\text{m}^3$.

Based on the ISCST2 PSD Class I screening modeling results, a supplemental air quality analysis was performed with the MESOPUFF II long-range transport model. As discussed in Appendix F, a long-range transport model is more appropriate for estimating maximum impacts for the proposed cogeneration facility, because the facility is located 120 km from the Class I area. MESOPUFF II is a more accurate model than ISCST2 when evaluating impacts at such a distance. This is consistent with the past applications of the model by FDER, EPA, and the National Park Service.

A description of the MESOPUFF II model, including prior use in the State of Florida, the modeling approach and meteorological data utilized, and the modeling results, are presented in Appendix F. The MESOPUFF II modeling results indicate that Sol-Energy's contribution to the HSH ISCST2 impacts range from 0.00 to 0.12 $\mu\text{g}/\text{m}^3$, which are lower than the ISCST2 predicted values. Therefore, from Tables E-3 and F-4, substitution of the proposed cogeneration facility's contribution reduces the total source predicted impacts to 4.21 $\mu\text{g}/\text{m}^3$ or less. This concentration is less than the allowable 24-hour PSD increment of 5 $\mu\text{g}/\text{m}^3$. Therefore, the proposed cogeneration facility will comply with all allowable SO_2 PSD Class I increments.

6.9.5 TOXIC IMPACT ANALYSIS

The maximum impacts of regulated and nonregulated toxic air pollutants that will be emitted by the Sol-Energy facility are presented in Table 6-18. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the respective FDER no-threat level (NTL). The table shows

Table 6-18. Maximum Impacts of Toxic Pollutants for Sol-Energy Cogeneration Facility (total all boilers)

Pollutant	Maximum Hourly Emissions ^a (lb/hr)	Concentrations ($\mu\text{g}/\text{m}^3$)					
		8-Hour		24-Hour		Annual	
		Impact	NTL	Impact	NTL	Impact	NTL
Ammonia	44.2	6.4	180	4.2	43.2	--	--
Antimony	0.032	0.005	5	0.003	1.2	0.0002	0.3
Arsenic	0.22	0.03	2	0.02	0.48	0.00029	0.00023
Barium	0.68	0.10	5	0.07	1.2	0.004	50
Beryllium	0.0054	0.0008	0.02	0.0005	0.0048	0.00003	0.00042
Bromine	1.96	0.283	7	0.2	1.68	--	--
Cadmium	0.0072	0.001	0.5	0.0007	0.12	0.00005	0.00056
Chromium metals	0.20	0.03	5	0.02	1.2	0.001	1000
Chromium +6	0.050	0.01	0.5	0.005	0.12	0.000069	0.000083
Cobalt	0.66	0.10	0.5	0.06	0.12	--	--
Copper	0.16	0.02	10	0.02	2.4	--	--
Dioxins/Furans	5.1E-07	--	--	--	--	3.2E-09	2.2E-08
Fluoride	22.0	3.2	25	2.1	6	--	--
Formaldehyde	0.90	0.1	4.5	0.09	1.08	0.006	0.077
Hydrogen Chloride	72.6	10.5	70	7.0	16.8	0.5	7.0
Indium	0.17	0.02	1	0.02	0.24	--	--
Manganese	1.06	0.15	50	0.1	12	--	--
Mercury	0.0078	0.001	0.5	0.0007	0.12	0.00005	0.3
Molybdenum	0.34	0.05	50	0.03	12	--	--
Nickel	0.94	0.14	0.5	0.09	0.12	0.0014	0.0042
Phosphorus	0.80	0.12	1	0.08	0.24	--	--
Selenium	0.05	0.007	2	0.005	0.48	--	--
Silver	0.04	0.006	0.1	0.004	0.024	0.0003	3
Thallium	--	--	--	--	--	--	--
Tin	0.22	0.03	1	0.02	0.24	--	--
Zinc	0.56	0.08	10	0.05	2.4	--	--
Zirconium	0.12	0.02	50	0.01	12	--	--

Note: NTL = no-threat level.

Maximum concentrations determined with ISCST2 model and West Palm Beach meteorological data for 1982 to 1986.

Highest predicted concentration ($\mu\text{g}/\text{m}^3$) for a 10 g/s (79.365 lb/hr) emission rate:

8-hour = 11.44, 24-hour = 7.62, and Annual = 0.50

^a Total both boilers.^a Based on maximum annual average emission rate of 0.20 TPY total both boilers (avg. of 0.046 lb/hr).^b Based on maximum annual average emission rate of 0.047 TPY total both boilers (avg. of 0.011 lb/hr).^c Based on maximum annual average emission rate of 0.95 TPY total both boilers (avg. of 0.22 lb/hr).

that all toxic pollutant impacts will be below respective NTLs, except for arsenic for the annual averaging time. These arsenic impacts are based on a conservative analysis which assumes 3 percent of the wood waste steam for the facility is treated wood.

Review of the modeling results for arsenic show that the annual NTL is predicted to be met at a distance of 4 km and beyond from the proposed facility. There are no residences or other public or private buildings, other than Osceola Farms buildings, located within 4 km of the proposed facility. This area consists totally of sugar cane fields. In addition, the NTL is based on a 1 in 1 million risk of cancer. EPA has promulgated risk factors for toxic substances, including arsenic, based on a 1 in 100,000 risk of cancer. The predicted maximum annual impact of arsenic of $0.00029 \mu\text{g}/\text{m}^3$ is well below the EPA promulgated level of $0.000023 \mu\text{g}/\text{m}^3$ based on 1 in 100,000 risk. Based on these considerations, no adverse effects due to the proposed facility are expected.

7.0 ADDITIONAL IMPACT ANALYSIS

7.1 IMPACTS ON SOILS AND VEGETATION

7.1.1 VICINITY OF SOL-ENERGY

The primary crop in the area of the Sol-Energy site is sugar cane. Soils are primarily organic peat-type soils. As described in the air quality impact analysis (Section 6.0), the maximum predicted SO₂ concentrations in the vicinity of the site as a result of the proposed cogeneration facility are predicted to be below the AAQS for SO₂. Since the AAQS are designed to protect the public welfare, including effects upon soils and vegetation, no detrimental effects on soils or vegetation should occur in this area. It is also reiterated that the long-term average SO₂ emission rate of 1,000 TPY from both the Flo-Energy and Sol-Energy cogeneration facilities represents no increase over the current annual SO₂ emission rate from the existing Okeelanta and Osceola Farms sugar mills.

7.1.2 PSD CLASS I AREA

This section focuses on the ecological effects of the proposed facility's impacts on Air Quality Related Values (AQRV), as defined under PSD regulations, in the Everglades National Park (ENP). The ENP is located approximately 120 km south of the Sol-Energy site. The AQRVs are defined as being:

"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 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 freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent upon these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) are also evaluated.

Only the pollutant SO₂ is considered in this analysis, since the proposed project will not result in a significant net increase in emissions of any criteria pollutant except SO₂.

7.1.2.1 Impacts to Vegetation

Sulfur is an essential plant nutrient which is normally taken up as sulfate ions by the roots. 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, and they interact with enzymes, compete with normal metabolites, and interfere with a variety of cellular functions (Horsman and Wellburn, 1976). However, sulfite is oxidized to sulfate ions within the leaf. These sulfate ions can then be used by the plant as a nutrient. Small amounts of sulfite can be oxidized in the plant before they induce harmful effects.

SO₂ at elevated levels in the ambient air has long been known to cause injury to plants. Acute SO₂ injury usually develops within a few hours or days of exposure. Symptoms include marginal, flecked, and/or intercostal necrotic areas that initially appear water-soaked and dullish green. This type 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).

Many studies have been conducted to determine the effects of high-concentration, short-term SO₂ exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are potentially injured by 3-hour exposure to SO₂ concentrations ranging from 790 to 1,570 µg/m³. Intermediate plants include locust and sweetgum. These species can be injured by 3-hour exposure to SO₂ concentrations ranging from 1,570 to 2,100 µg/m³. Resistant species, which are not injured at concentrations below 2,100 µg/m³ for 3 hours, include white oak and dogwood (EPA, 1982).

A study of native Floridian vegetation species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 µg/m³ SO₂ for 8 hours were not visibly damaged. This finding supports the levels cited by other researchers on the effects of SO₂ 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 were visibly injured when exposed to an SO₂ concentration of 920 µg/m³ for 3 hours.

Jack pine seedlings exposed to SO₂ concentrations of 470 to 520 µg/m³ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn,

1978). Black oak exposed to $1,310 \mu\text{g}/\text{m}^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979).

In a recent study, two lichen species indigenous to the ENP area exhibited signs of SO_2 damage in the form of decreased biomass gain and photosynthetic rate as well as membrane leakage when exposed to concentrations of 200 to $400 \mu\text{g}/\text{m}^3$ for 6 hours/week for 10 weeks (Hart et al., 1988).

As described in Section 6.0, the maximum 3-hour and 24-hour predicted increment consumption SO_2 concentrations expected at the point of maximum impact in the ENP are less than $23 \mu\text{g}/\text{m}^3$ and $5 \mu\text{g}/\text{m}^3$, respectively. Upon comparison of these concentrations to those causing injury to native species, it is evident that SO_2 -sensitive species (or more tolerant species) would not be damaged by the predicted concentrations. These levels are less than 15 percent of the most conservative concentration ($200 \mu\text{g}/\text{m}^3$) that has been shown to cause injury to SO_2 -sensitive species.

The 24-hour and annual SO_2 concentrations predicted within the ENP due to all increment-consuming sources (4.2 and $0.7 \mu\text{g}/\text{m}^3$, respectively), when added to background concentrations of 21 and $8 \mu\text{g}/\text{m}^3$, respectively, result in total SO_2 impacts of 25 and $9 \mu\text{g}/\text{m}^3$, respectively. These levels are much lower than those known to cause damage to test species. By comparison of these levels, it is apparent that the modeled 24-hour incremental increase of SO_2 is well below the concentrations that caused damage in SO_2 -sensitive plants. The predicted annual increment increase in SO_2 ($0.7 \mu\text{g}/\text{m}^3$) adds slightly to background levels of this gas and poses only a minimal threat to area vegetation.

On a long-term basis, SO_2 levels in the ENP will not increase as a result of the Sol-Energy and Flo-Energy cogeneration projects. As described previously, annual average SO_2 emissions from the projects will not increase above current levels on a long-term basis.

7.1.2.2 Impacts to Soils

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

1. Increased soil acidification;
2. Alteration in cation exchange;
3. Loss of base cations; and
4. 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.

The soils of the Everglades National Park are generally classified as histosols or entisols. Histosols (peat soils) are organic and have extremely high buffering capacities based on their CEC, base saturation, and bulk density. Therefore, they would be relatively insensitive to atmospheric inputs. The entisols are shallow sandy soils overlying limestone, such as the soils found in the pinelands. 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 calcium carbonate (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 ENP from facility emissions precludes any significant impact on soils.

7.1.2.3 Impacts to Wildlife

A wide range of physiological and ecological effects to fauna has been reported for gaseous and particulate pollutants (Newman, 1980; Newman and Schreiber, 1988). The most severe of these effects have been observed at concentrations above the secondary ambient air quality standards. 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 7-1.

The major air quality risk to wildlife in the United States is from continuous exposure to pollutants above the national ambient air quality standards. 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, 1980).

Table 7-1. Examples of Reported Effects of Sulfur Dioxide on Wildlife at Concentrations Below National Secondary Ambient Air Quality Standards

Reported Effect	Concentration ($\mu\text{g}/\text{m}^3$)	Exposure
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

Source: Newman and Schreiber, 1988.

For impacts on wildlife, the lowest threshold values of SO₂ reported to cause physiological changes are shown in Table 7-1. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from SO₂ are therefore expected. These results are considered indications of the risk of other air pollutants predicted to be emitted from the facility.

7.2 IMPACTS ON VISIBILITY

The visibility analysis required by PSD regulations is directed primarily toward Class I areas. The CAA amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration caused by various pollutants. The Class I area nearest to the proposed facility is the Everglades National Park, located about 120 km south of the proposed site.

A Level-1 visibility screening analysis was performed to determine the potential adverse visibility effects using the approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988c). The level-1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts higher than expected). The EPA model, VISCREEN, was used for this analysis. Model input and output results are presented in Table 7-2. The total PM, NO_x, and sulfuric acid mist emissions from the proposed facility, as presented in Section 3.4, were used as input to the model. As indicated, the maximum visibility impacts caused by the facility do not exceed the screening criteria inside or outside the ENP Class I area. As a result, there is no significant impact upon visibility predicted for the Class I areas.

7.3 IMPACTS DUE TO ASSOCIATED POPULATION GROWTH

There will be a small number of temporary construction workers during construction. There will be about 20 permanent employees at Sol-Energy associated with the operation of the cogeneration facility. These increases are minor, and there will be no significant impacts on air quality caused by associated population growth.

Table 7-2. Results of Visibility Screening Analysis

Visual Effects Screening Analysis for Source: SOL-ENERGY COGENERATION FACILITY Class I Area: EVERGLADES NATIONAL PARK								
*** Level-1 Screening ***								
Input Emissions for								
Particulates	109.30	TON/YR						
NOx (as NO2)	436.50	TON/YR						
Primary NO2	.00	TON/YR						
Soot	.00	TON/YR						
Primary SO4	31.10	TON/YR						
**** Default Particle Characteristics Assumed								
Transport Scenario Specifications:								
Background Ozone:	.04	ppm						
Background Visual Range:	40.00	km						
Source-Observer Distance:	120.00	km						
Min. Source-Class I Distance:	120.00	km						
Max. Source-Class I Distance:	140.00	km						
Plume-Source-Observer Angle:	11.25	degrees						
Stability:	6							
Wind Speed:	1.00	m/s						
R E S U L T S								
Asterisks (*) indicate plume impacts that exceed screening criteria								
Maximum Visual Impacts INSIDE Class I Area Screening Criteria ARE NOT Exceeded								
Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	84.	120.0	84.	2.00	.052	.05	.000
SKY	140.	84.	120.0	84.	2.00	.016	.05	-.001
TERRAIN	10.	84.	120.0	84.	2.00	.013	.05	.000
TERRAIN	140.	84.	120.0	84.	2.00	.003	.05	.000
Maximum Visual Impacts OUTSIDE Class I Area Screening Criteria ARE NOT Exceeded								
Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	70.	114.1	99.	2.00	.054	.05	.000
SKY	140.	70.	114.1	99.	2.00	.017	.05	-.001
TERRAIN	10.	60.	109.7	109.	2.00	.017	.05	.000
TERRAIN	140.	60.	109.7	109.	2.00	.005	.05	.000

8.0 PROPOSED PERMIT CONDITIONS

Presented in this section are proposed permit conditions for the Sol-Energy cogeneration facility. These proposed conditions reflect typical conditions issued in FDER construction permits for electric utility power plants. In addition, Palm Beach County's zoning approval for Sol-Energy requires that Sol-Energy request of FDER that certain conditions be incorporated into FDER's construction permit for the facility (the zoning conditions are contained in Appendix C). Accordingly, proposed permit conditions have been developed for the Sol-Energy cogeneration facility, which includes the conditions recommended by Palm Beach County. It is requested that FDER consider these proposed conditions in issuing the air construction and operating permits for the facility.

Construction Details

1. Construction of the proposed cogeneration facility shall reasonably conform to the plans described in the application.
2. Boilers No. 1 and 2 shall be of the spreader stoker type.
3. Each boiler may have an individual stack, and each stack must have a minimum height of 180 feet. The stack sampling facilities for each stack must comply with F.A.C. Rule 17-2.700(4).
4. Each boiler shall be equipped with instruments to measure steam production, steam pressure, and steam temperature.
5. Each boiler shall be equipped with a:
 - Electrostatic precipitator (ESP) designed for at least 98 percent removal of particulate matter;
 - Selective non-catalytic reduction (SNCR) system designed for at least 40 percent removal of NO_x; and
 - Carbon injection system (or equivalent) for mercury emissions control.
6. The permittee shall install and operate continuous monitoring devices for each main boiler exhaust for opacity, nitrogen oxides (NO_x), and carbon monoxide (CO). The monitoring devices shall meet the applicable requirements of Section 17-2.710, F.A.C., and 40 CFR 60.47a. The opacity monitor may be placed in the duct work between the electrostatic precipitator and the stack.

A flue gas oxygen meter shall be installed for each unit to continuously monitor a representative sample of the flue gas. The oxygen monitor shall be used with automatic feedback or manual controls to continuously maintain air/fuel ratio parameters at an optimum. Operating procedures shall be established based on the initial performance tests required by Condition 21 below. The document "Use of Flue Gas Oxygen Meter as BACT for Combustion Controls" may be used as a guide. An operating plan shall be submitted to the Department within 90 days of completion of such tests.

7. For the ESP, SNCR and mercury control systems:

a. The permittee shall submit to the Department copies of technical data pertaining to the selected PM, NO_x, and mercury emissions control within thirty (30) days after it becomes available. These data should include, but not be limited to, guaranteed efficiency and emission rates and major design parameters such as specific collection area, air/cloth ratio, and air flow rate. The Department may review these data to determine whether the selected control equipment is adequate to meet the emission limits specified in Condition 19 below. Such review shall be completed within 30 days of receipt of the technical data.

8. For the fly ash handling and mercury control system reactant storage systems:

a. The particulate matter control system for the storage silos shall be designed to achieve a 0.01 gr/acf outlet dust loading. The permittee must submit to the Department copies of technical data pertaining to the selected particulate emissions control for the mercury control system reactant storage silos within thirty (30) days after it becomes available. These data should include, but not be limited to guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and air flow rate. The Department may review these data to determine whether the selected control device is adequate to meet the emission limits specified in Condition 18 below. Such review shall be completed within 30 days of receipt of the technical data.

b. The fly ash handling system (including transfer points and storage bin) shall be enclosed.

9. Prior to operation of the source, the permittee shall submit to the Department a plan or procedure that will allow the permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

10. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented.

Operational and Emission Restrictions

11. The proposed cogeneration facility steam generating units shall be constructed and operated in accordance with the capabilities and specifications described in the application. The facility shall not exceed 74.9 (gross) megawatt generating capacity and the maximum heat input rate for each steam generator of 665 MMBtu/hr when burning 100 percent biomass and 460 MMBtu/hr when burning 100 percent No. 2 fuel oil or low sulfur coal. Maximum heat input to the entire facility (total two boilers) shall not exceed 7.00×10^{12} Btu per year.

12. Any wood waste materials burned as fuel shall be substantially free from painted and chemically treated wood, household garbage, toxic or hazardous materials or waste, and special waste.

13. Any fuel oil burned in the facility shall be "new" No. 2 fuel oil with a maximum sulfur content equivalent to 0.5 lb SO₂/MMBtu. "New" oil means an oil which has been refined from crude oil and has not been used.

14. Any coal burned in the facility shall be low sulfur coal with a maximum sulfur content equivalent to 1.2 lb SO₂/MMBtu.

15. The consumption of coal shall not exceed 25 percent of the total heat input to each boiler unit in any calendar quarter.

16. The permittee shall maintain a daily log of the amounts and types of fuel used. The amount, heating value, sulfur content, and equivalent SO₂ emission rate (in lb/MMBtu) of each fuel oil and coal delivery shall be kept in a log. These logs shall be kept for at least two years.

17. During the first three years of cogeneration facility operation, the existing Boilers No. 2, 3, 4, 5, and 6 may be retained for standby operation. These boilers may be operated only when all three cogeneration boilers are shutdown. During operation, these boilers must meet all requirements in the current operating permits for the boilers. These boilers shall be shutdown and rendered incapable of operation within three (3) years of commercial startup of the cogeneration facility, but no later than January 1, 1999.

18. For the coal, fly ash, and mercury control system reactant handling facilities:

- a. All conveyors and conveyor transfer points shall be substantially enclosed to preclude PM emissions (except those directly associated with the coal stacker/reclaimer, for which enclosure is operationally infeasible).
- b. Inactive coal storage piles shall be shaped, compacted and oriented to minimize wind erosion.
- c. Water sprays or chemical wetting agents and stabilizers shall be applied to storage piles, handling equipment, etc. during dry periods and as necessary to all facilities to maintain an opacity of less than or equal to 5 percent, except when adding, moving or removing coal from the coal pile, which would be allowed no more than 20 percent opacity.
- d. The mercury control system reactant storage silos shall be maintained at a negative pressure while operating with the exhaust vented to a control system. Particulate matter emissions from each of the three silos shall not exceed 0.01 gr/acf. A visible emission reading of 5 percent or less may be used to establish compliance with this emission limit. A visible emission reading of 5 percent opacity or greater will not create a presumption that the 0.01 gr/acf emission limit is being violated; however, such a reading may require the permittee to perform a stack test on the storage silo exhaust vent, as set forth in Condition 21 below. A visible emission test is to be performed annually on each silo.

19. Based on a maximum heat input to each boiler of 665 MMBtu/hr for biomass fuels and 460 MMBtu/hr for No. 2 fuel oil and coal, stack emissions shall not exceed those shown in the following table:

Pollutant	Emission Limit (per boiler)						Total Two Boilers (TPY)
	Biomass		No.2 Oil		Bit. Coal		
	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	(lb/MMBtu)	(lb/hr)	
Particulate (TSP)	0.03	20.0	0.03	13.8	0.03	13.8	105.0
Particulate (PM10)	0.03	20.0	0.03	13.8	0.03	13.8	105.0
Sulfur Dioxide							
24-hour average	0.10	66.5	0.5	230.0	1.2	552.0	—
Annual average ^a	0.02	—	0.5	—	1.2	—	1,071.5
Nitrogen Oxides							
Annual average ^a	0.12	—	0.12	—	0.17	—	436.5
Carbon Monoxide							
8-hour average	0.35	232.8	0.2	92.0	0.2	92.0	1,225.0
Volatile Organic Compounds	0.06	39.9	0.03	13.8	0.03	13.8	210.0
Lead	2.5x10 ⁻⁵	0.017	8.9x10 ⁻⁷	0.0004	6.4x10 ⁻⁵	0.029	0.11
Mercury	5.5x10 ⁻⁶ ^b 0.29x10 ⁻⁶ ^c	0.0037 ^b 0.00019 ^c	2.4x10 ⁻⁶	0.0011	8.4x10 ⁻⁶	0.0039	0.0139
Beryllium	—	—	3.5x10 ⁻⁷	0.00016	5.9x10 ⁻⁶	0.0027	0.0049
Fluorides	—	—	6.3x10 ⁻⁶	0.003	0.024	11.0	19.76
Sulfuric Acid Mist	0.003	2.00	0.015	6.9	0.036	16.6	31.13

^a Compliance based on 30-day rolling average, per 40 CFR 60, Subpart Da.

^b Emission limit for bagasse.

^c Emission limit for wood waste.

20. The following conditions apply to the total combined SO₂ emissions from the Sol-Energy and Flo-Energy cogeneration projects:

a. SO₂ emissions shall not exceed an average of 1,000 tons per year over the life of the projects.

b. If the Palm Beach County government makes available 200,000 tons or more of biomass fuel each year to the Sol-Energy and Flo-Energy cogeneration projects, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the SO₂ emissions shall not exceed 1,500 tons per year for that year, and shall not exceed an average of 1,300 tons per year for each five year incremental period.

c. If the Palm Beach County government cannot make available 200,000 tons or more of biomass fuel each year to the Sol-Energy and Flo-Energy cogeneration projects, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the SO₂ emissions shall not exceed 1,700 tons per year for that year, and shall not exceed an average of 1,500 tons per year for each ten year incremental period.

d. The allowable average SO₂ emissions for the five and ten year incremental periods described above shall be calculated on a weighted average for any period in which both cases occur (years in which biomass is made available and years in which biomass is not made available).

e. SO₂ emissions shall include all emissions for the Sol-Energy and Flo-Energy projects, including the existing boilers at the Okeelanta and Osceola facilities, if they are in operation during initial project operation.

Compliance Requirements

21. Stack Testing

a. Within 60 calendar days after achieving the maximum capacity at which each unit will be operated, but no later than 180 operating days after initial startup, the permittee shall conduct performance tests for particulates, NO_x, and visible emissions during normal operations near (i.e., within 10 percent) 665 MMBtu/hr heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a.

b. Compliance with emission limitations stated in Condition No. 20 above shall be demonstrated using EPA Methods, as contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources), or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants), or any other method as approved by the Department, in accordance with F.A.C. Rule 17-2.700. A test protocol shall be submitted for approval to the Bureau of Air Regulation at least 90 days prior to testing.

<u>EPA Method</u>	<u>For Determination of</u>
1	Selection of sample site and velocity traverses.
2	Stack gas flow rate when converting concentrations to or from mass emission limits.
3	Gas analysis when needed for calculation of molecular weight or percent O ₂
4	Moisture content when converting stack velocity to dry volumetric flow rate for use in converting concentrations in dry gases to or from mass emission limits.
5	Particulate matter concentration and mass emissions.
201 or 201A	PM10 emissions.
6, 6C, or 19	Sulfur dioxide emissions from stationary sources.
7, 7C, or 19	Nitrogen oxide emissions from stationary sources.
9	Visible emission determination of opacity. -- At least three one hour runs to be conducted simultaneously with particulate testing. -- At least one truck unloading into the mercury reactant storage silo (from start to finish).
10	Carbon monoxide emissions from stationary sources.
12 or 101A	Lead concentration from stationary sources.
13A or 13B	Fluoride emissions from stationary sources.
18, 25, or 25A	Volatile organic compounds concentration.
101A or 108	Mercury emissions.
104	Beryllium emission rate and associated moisture content.

22. Performance tests shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. The permittee shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

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

24. Stack tests for particulates, NO_x, SO₂, CO, VOC, lead, mercury, beryllium, fluorides and visible emissions shall be performed once every six months during the first two years of facility operation in accordance with Conditions 21, 22, and 23 above. If the test results for the first two years of operation indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the tests will thereafter occur according to the following schedule:

- Annually for particulates, NO_x, CO, VOC, mercury, and visible emissions
- Once every five years (at permit renewal time) for SO₂, lead, beryllium, and fluorides.

In the event that the first two years of testing show non-compliance with a particular pollutant, then the frequency of testing of that pollutant shall continue to occur once every six months until the facility achieves a sustained two-year period of compliance.

25. After conducting the initial stack tests required under Condition 24 above, a fuel management plan shall be submitted to the Department and Palm Beach County within 90 days specifying the fuel types and fuel quantities to be burned in the facility in order to not exceed the facility annual mercury emission limit specified in Condition 19 above. The plan shall include mercury emission factors based on stack testing, and may include revised mercury emission factors and baseline emission estimates for the existing Osceola Farms facility.

Reporting Requirements

26. Stack monitoring, fuel usage and fuel analysis data shall be reported to the Department's Southeast District Office and to the Palm Beach County Health Unit on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part 60, Sections 60.7 and 60.49a, and in accordance with Section 17-2.08, F.A.C.

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APPENDIX A

**DERIVATIONS OF POLLUTANT EMISSION FACTORS
FOR PROPOSED FACILITY**

09/17/92

All pollutant emissions factors used in emission calculations are expressed in terms of lb/MMBtu for biomass, fuel oil, and coal. The basis for the emission factors is presented below.

A. Biomass

Heating value of bagasse: 4,250 Btu/lb (wood waste has higher heating value).

1. PM: The emission factor is based on the NSPS = 0.03 lb/MMBtu

Sample calculation: Activity Factor = 7.00×10^{12} Btu/yr; 665 MMBtu/hr

PM (lb/hr) = 665 MMBtu/hr x 0.03 lb/MMBtu = 20.0 lb/hr

PM (TPY) = 7.00×10^{12} Btu x 0.03 lb/MMBtu x ton/2,000 lb

= 105.0 TPY

2. SO₂:

- a. Average

Industry data indicate an average of 0.009% sulfur (dry basis) in bagasse, or 0.0043% (wet basis), @ 4,250 Btu/lb wet bagasse. Sulfur in wood waste is similar (reference AP-42).

$0.000043 \text{ lb S/lb} \times 2 \text{ lb SO}_2/\text{lb S} + 4,250 \text{ Btu/lb} \times 10^6$

= 0.020 lb/MMBtu

SO₂ (TPY) = $7.00 \times 10^{12} \times 0.020/10^6 + 2,000 = 70.0 \text{ TPY}$

- b. Maximum

Based on maximum sulfur content of bagasse of approximately

0.045%, dry basis, or 0.022%, wet basis

$0.00022 \times 2 + 4,250 \times 10^6 = 0.10 \text{ lb/MMBtu}$

SO₂ (lb/hr) = 665 MMBtu/hr x 0.10 lb/MMBtu = 66.5 lb/hr

3. NO_x: The emission factor used is based upon the boiler design and SNCR control system. The emission factor is 0.12 lb/MMBtu, 30-day rolling average.

NO_x (avg. lb/hr) = $665 \times 10^6 \times 0.12/10^6 = 79.8 \text{ lb/hr}$

NO_x (TPY) = $7.00 \times 10^{12} \times .12/10^6 = 420.0 \text{ TPY}$

4. CO, VOC: The emission factors used are based upon boiler design.

CO = 0.35 lb/MMBtu (8-hour average).

VOC = 0.06 lb/MMBtu for biomass.

= 0.03 lb/MMBtu for oil and coal.

5. Hg:

- a. Bagasse

The emission factor is based upon the mercury content in the sugar cane leaves of 0.068 ppm (dry) and 0.033 ppm (wet) (Patrick, 1991) and the mercury control system. The emission factor is:

$1 \text{ lb} \times 0.033/10^6 + 4,250 \text{ Btu/lb} = 7.8 \times 10^{-6} \text{ lb/MMBtu.}$

Mercury control system estimated 30% removal:

$7.8 \times 10^{-6} \times (1 - 0.30) = 5.5 \times 10^{-6} \text{ lb/MMBtu}$

b. Wood Waste

The article entitled "Air Toxics Emissions from Wood-Fired Boilers" (Sassenrath, 1991) presents mercury emission data from three wood/bark-fired stoker spreader boilers equipped with ESP controls. The three boilers averaged $0.23 \mu\text{g}/\text{dscm}$ in the exhaust gases, which is approximately equivalent to $0.41 \times 10^{-6} \text{ lb/MMBtu}$ for the Okeelanta cogeneration boilers.

6. Sulfuric Acid Mist: From the EPA Publication AP-42, sulfuric acid mist emissions are estimated to be 3 percent of the sulfur dioxide emissions. The average emission factor is $0.03 \times 0.02 \text{ lb/MMBtu} = 6.0 \times 10^{-4} \text{ lb/MMBtu}$.

7. Beryllium, Fluorides: Seminole Kraft Corporation emission tests concluded that there were no detectable emissions of beryllium while burning wood. It is assumed that bagasse is similar in nature. There is no available data on fluorides emissions from biomass combustion.

8. Arsenic, Cadmium, Chromium, Copper, Lead, Manganese, Nickel, Zinc, Formaldehyde, Dioxins and Furans: The emission factors were based on "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath as published in 1991 Technical Association of Pulp and Paper Industry (TAPPI) Proceedings. Except for formaldehyde, dioxins, and furans, the emission factors are reported as parts per million by weight in the particulate emissions. Three stoker boilers equipped with ESPs were tested. The average of the three was used and then converted to lb/MMBtu :

$$\text{Air Toxic } (\mu\text{g/g PM}) = \text{lb Air Tox}/10^6 \text{ lb PM} = \text{ppm PM}$$

$$\text{Emission limit for PM} = 0.03 \text{ lb PM/MMBtu}$$

$$\text{Air Tox}(\text{lb/MMBtu}) = 0.03 \text{ lb/MMBtu} \times \text{Air Tox ppm}/10^6$$

In addition, emissions of arsenic, chromium, and copper are estimated for the case of 5% treated wood burning (see below).

Sample calculation:

$$\text{Arsenic: } 92 \mu\text{g/g PM} \times 0.03 (\text{lb/MMBtu}) = 2.8 \times 10^{-6} \text{ lb/MMBtu}$$

Arsenic	92 $\mu\text{g/g PM}$	$= 2.76 \times 10^{-6} \text{ lb/MMBtu}$
Cadmium	181 $\mu\text{g/g PM}$	$= 5.43 \times 10^{-6} \text{ lb/MMBtu}$
Chromium	206 $\mu\text{g/g PM}$	$= 6.18 \times 10^{-6} \text{ lb/MMBtu}$
Chromium ⁺⁶ :	assume as 20% of total chromium	$= 1.24 \times 10^{-6} \text{ lb/MMBtu}$
Copper	1,196 $\mu\text{g/g PM}$	$= 3.59 \times 10^{-5} \text{ lb/MMBtu}$
Lead	822 $\mu\text{g/g PM}$	$= 2.5 \times 10^{-5} \text{ lb/MMBtu}$
Manganese	26,615 $\mu\text{g/g PM}$	$= 7.98 \times 10^{-4} \text{ lb/MMBtu}$
Nickel	1,472 $\mu\text{g/g PM}$	$= 4.41 \times 10^{-5} \text{ lb/MMBtu}$
Zinc	14,130 $\mu\text{g/g PM}$	$= 4.24 \times 10^{-4} \text{ lb/MMBtu}$

Sample calculation for cadmium: Activity Factor = 7.00×10^{12} Btu/yr

$$\begin{aligned} \text{Cd} &= 5.43 \times 10^{-6} \text{ lb/MMBtu} \times 7.00 \times 10^{12} \text{ Btu/yr} + 2,000 \\ &= 0.019 \text{ TPY.} \end{aligned}$$

Formaldehyde is presented in parts per billion (ppb). By way of the ideal gas law and known test conditions, the emission factor is converted to lb/MMBtu. The formaldehyde levels were taken from three spreader stokers equipped with ESPs. The average emission was 0.530 ppm in the exhaust gases. For the proposed cogeneration boilers, the maximum gas flow rate is 182,000 dscfm.

$$0.530/10^6 \times 182,000 \text{ dscfm} \times 60 \text{ min/hr} = 5.78 \text{ ft}^3/\text{hr formaldehyde}$$

From the ideal gas law: $PV=mRT$, solving for m (mass)

$$m = P \times V + (R \times T)$$

$$\begin{aligned} m(\text{lb}) &= 2116.8 \text{ lb}_f/\text{ft}^2 \times 5.78 \text{ ft}^3/\text{hr} + (1545 \text{ ft-lb}_f/30 \text{ lb}_m \cdot ^\circ\text{R} \times 528 ^\circ\text{R}) \\ &= 0.45 \text{ lb/hr} \end{aligned}$$

The maximum firing rate of biomass is 665 MMBtu/hr.

$$\text{Form} = 0.45 \text{ lb/hr} \times \text{hr}/665 \text{ MMBtu} = 6.77 \times 10^{-4} \times \text{lb/MMBtu}$$

Sample calculation: Activity Factor = 7.00×10^{12} Btu/yr

$$\begin{aligned} \text{Form(TPY)} &= 0.000677 \text{ lb/MMBtu} \times 7.00 \times 10^{12} \text{ Btu/yr} + 2,000 \\ &= 2.37 \text{ TPY} \end{aligned}$$

9. Antimony, Barium, Phosphorus, Selenium, Silver, Thallium, Tin, and Zirconium: Emission factors were determined from the results of emission tests conducted on wood fired boilers at Seminole Kraft Corporation in 1990. These boilers were equipped with wet scrubbers which have a lower removal efficiency than ESPs. Therefore, these calculated emissions on an ESP system are conservative. The emission factors were reported as lb Air Toxic/ton wood fuel burned. A further assumption was that wood and bagasse have the same emission factor. The emission factors were converted to lb/MMBtu.

$$\begin{aligned} \text{lb Air Tox/ton fuel} \times \text{ton fuel}/2,000 \text{ lb fuel} \times \text{lb fuel}/4,250 \text{ Btu} \times \\ 10^6 &= \text{lb Air tox/MMBtu} \end{aligned}$$

Antimony: undetectable levels in gas stream
Barium: $0.0009 \text{ lb/ton} = 1.06 \times 10^{-4} \text{ lb/MMBtu}$
Phosphorus: $0.003 \text{ lb/ton} = 3.53 \times 10^{-4} \text{ lb/MMBtu}$
Selenium: undetectable levels in gas stream
Silver: $0.00025 \text{ lb/ton} = 2.94 \times 10^{-5} \text{ lb/MMBtu}$
Thallium: undetectable levels in gas stream

Sample calculation: Activity Factor = 7.00×10^{12} Btu/yr

Barium: $1.06 \times 10^{-4} \times 7.00 \times 10^{12} + 2,000 + 10^6 = 0.37$ TPY

10. Bromine, Cobalt, Indium, Molybdenum, Tin, and Zirconium: Emission factors are available from the VOC and PM Speciation Data Base, Updated in October 1989. The factors are for a wood-fired boiler controlled by a wet scrubber.

Bromine: 0.01260 lb/ton = 1.47×10^{-3} lb/MMBtu
Cobalt: 0.00423 lb/ton = 4.98×10^{-4} lb/MMBtu
Indium: 0.00108 lb/ton = 1.27×10^{-4} lb/MMBtu
Molybdenum: 0.00216 lb/ton = 2.54×10^{-4} lb/MMBtu
Tin: 0.00137 lb/ton = 1.62×10^{-4} lb/MMBtu
Zirconium: 0.00079 lb/ton = 9.29×10^{-5} lb/MMBtu

Example Calculation:

Bromine (TPY) = $0.00147/10^6 \times 7.00 \times 10^{12} + 2,000 = 5.15$ TPY

11. Hydrogen Chloride: Emission factor is based on fuel analysis information from Seminole Kraft Corporation. The concentration of chlorine in wood waste was found to average 153 ppm. In converting to lb/MMBtu, the emission factor of chlorine must also be converted to account for the change of form in the emission to HCl.

153 lb Cl + 10^6 lb fuel x lb fuel/4,250 Btu x 36 lb

HCl/35 lb Cl x $10^6 = 0.037$ lb/MMBtu.

Sample calculation: Activity Factor = 11.50×10^{12} Btu/yr

Cl (TPY) = $0.037/10^6 \times 7.00 \times 10^{12} + 2,000 = 129.5$ TPY

12. Dioxins and Furans: The emission factor for dioxins and furans from wood burning was obtained from "Air Toxic Emissions from Wood Fired Boilers", C. Sassenrath as published in 1991 TAPPI Proceedings. The average of two spreader stoker boilers equipped with a multiclone and ESP was 0.007 ng/dscm (expressed as 2,3,7,8 - TCDD equivalents). With a flowrate of 309,200 dscm/hr and firing at 665 MMBtu/hr, the emission factor for dioxin is:

0.007×10^{-9} g/dscm x 309,200 dscm/hr + 665 MMBtu/hr x lb/453.6 g
= 7.18×10^{-12} lb/MMBtu

The emission factor for furans is calculated in the same way. The average of two spreader stokers equipped with a multiclone and ESP was 0.366 ng/dscm (as toxic equivalents). The emission factor for furans is:

$0.366 \times 10^{-9} \times 309,200 + 665 + 453.6 = 3.75 \times 10^{-10}$ lb/MMBtu.

Sample calculation: Activity Factor = 7.00×10^{12} Btu/yr

$$\begin{aligned}\text{Dioxin (TPY)} &= 7.18 \times 10^{-12} \text{ lb/MMBtu} \times 7.00 \times 10^{12} \text{ Btu/yr} + 2,000 \\ &= 2.5 \times 10^{-8} \text{ TPY}\end{aligned}$$

$$\begin{aligned}\text{Furan (TPY)} &= 3.75 \times 10^{-10} \text{ lb/MMBtu} \times 7.00 \times 10^{12} + 2,000 \\ &= 1.3 \times 10^{-6} \text{ TPY}\end{aligned}$$

13. Ammonia

Maximum NH_3 slip will be 20 ppm based on vendor information.

Maximum flow rate per boiler = 293,000 acfm

$$\text{MW } \text{NH}_3 = 17$$

$$\text{PV} = mRT \quad M = \text{PV}/RT$$

$$\begin{aligned}M &= 2,116.8 \text{ lb}_f/\text{ft}^2 \times 293,000 \text{ ft}^3/\text{min} \times 60 \text{ min/hr} \times 17 \text{ lb}_m^{-0}\text{R}/1,545 \text{ ft-lb}_f \\ &+ (460 + 350)^0\text{R} \times 20/10^6 = 10.1 \text{ lb/hr each boiler}\end{aligned}$$

$$10.1 \text{ lb/hr} + 665 \times 10^6 = 0.015 \text{ lb/MMBtu}$$

14. Treated Wood Burning

Although Sol-Energy will not accept treated wood at the facility, a small amount of treated wood may be present in the wood waste stream. Emissions of several toxic air pollutants have been estimated to account for this possibility, assuming 3 percent of the wood waste is wood that has been treated with chromium copper arsenate (CCA).

Assume 4,250 Btu/lb of lumber (same as biomass)

$$\text{Density of white pine} = 27 \text{ lb/ft}^3$$

A. Maximum emissions

$$\begin{aligned}\text{Maximum biomass burning rate} &= 665 \times 10^6 \text{ Btu/hr} + 4,250 \text{ Btu/lb} \\ &= 156,471 \text{ lb/hr each boiler}\end{aligned}$$

$$\text{Treated lumber feed} = 3\% \text{ of biomass feed rate} = 4,694 \text{ lb/hr}$$

$$= 20.0 \times 10^6 \text{ Btu/hr}$$

$$4,694 \text{ lb/hr} + 27 \text{ lb/ft}^3 = 174 \text{ ft}^3/\text{hr treated wood}$$

Wood Treated with CCA:

Avg. mix of treated wood = 0.47 lb of CCA/ft³

174 ft³/hr x 0.47 lb CCA/ft³ = 81.8 lb/hr of CCA

CCA = 20% As₂O₅; MW = 230

As₂; MW = 150

20% x 150/230 = 13% As by weight

29% CrO₃; MW = 100

Cr; MW = 52

29% x 52/100 = 15% Cr by weight

11% CuO; MW = 80

Cu; MW = 64

11% x 64/80 = 9% Cu by weight

Electrostatic precipitator for particulate control--99% efficiency based on
"Impact of Particulate Emissions Control on the Control of Other MWC Air
Emissions" (EPA, 1990).

As = 81.8 x 0.13 x (1-0.99) = 0.106 lb/hr

0.106 lb/hr + 20.0x10⁶ Btu/hr = 5.31x10⁻³ lb/MMBtu

Cr = 81.8 x 0.15 x (1-0.99) = 0.123 lb/hr

Cr⁺⁶: 20% of Cr is Cr⁺⁶, remainder is metal

0.123 lb/hr x 0.20 = 0.0246 lb/hr

0.0246 + 20.0x10⁶ = 1.23x10⁻³ lb/MMBtu

Cr metal = 0.123 lb/hr x 0.80 = 0.098 lb/hr

0.098 + 20.0x10⁶ = 4.93x10⁻³ lb/MMBtu

Cu = 81.8 x 0.09 x (1-0.99) = 0.074 lb/hr

0.074 + 20.0x10⁶ = 3.68x10⁻³ lb/MMBtu

Arsenic

Biomass--97% @ 2.76x10⁻⁶ lb/MMBtu

Treated Wood--3% @ 5.31x10⁻³ lb/MMBtu

Weighted Average = 1.62x10⁻⁴ lb/MMBtu

Chromium

Biomass--97% @ 6.18x10⁻⁶ lb/MMBtu

Treated Wood--3% @ 4.93x10⁻³ lb/MMBtu

Weighted Average = 1.54x10⁻⁴ lb/MMBtu

Chromium⁺⁶

Biomass--97% @ 1.24×10^{-6} lb/MMBtu
Treated Wood--3% @ 1.23×10^{-3} lb/MMBtu
Weighted average = 3.81×10^{-5} lb/MMBtu

Copper

Biomass--97% @ 3.59×10^{-5} lb/MMBtu
Treated Wood--3% @ 3.68×10^{-3} lb/MMBtu
Weighted Average = 1.45×10^{-4} lb/MMBtu

B. Annual Emissions

On an annual basis, 3 percent of the wood waste amount equates to approximately 8,000 TPY of treated wood (0.07×10^{12} Btu/yr). Remainder of total heat input (6.93×10^{12} Btu/yr) would be from clean biomass. Thus, treated wood would represent 1 percent of total biomass on an annual basis. Calculations are similar to maximum hourly calculations.

Arsenic

Biomass--99% @ 2.76×10^{-6} lb/MMBtu
Treated wood--1% @ 5.31×10^{-3} lb/MMBtu
Weighted average-- 5.58×10^{-5} lb/MMBtu

Chromium

Biomass--99% @ 6.18×10^{-6} lb/MMBtu
Treated wood--1% @ 4.93×10^{-3} lb/MMBtu
Weighted average-- 5.54×10^{-5} lb/MMBtu

Chromium⁺⁶

Biomass--99% @ 1.24×10^{-6} lb/MMBtu
Treated wood--1% @ 1.23×10^{-3} lb/MMBtu
Weighted average-- 1.35×10^{-5} lb/MMBtu

Copper

Biomass--99% @ 3.59×10^{-5} lb/MMBtu
Treated wood--1% @ 3.68×10^{-3} lb/MMBtu
Weighted average-- 7.23×10^{-5} lb/MMBtu

B. No. 2 Fuel Oil

Heating value of No. 2 Fuel Oil: 138,000 Btu/gal

1. PM: The emission factor is based on the NSPS = 0.03 lb/MMBtu

Sample calculation: Activity Factor = 1.647×10^{12} Btu/yr

$$\begin{aligned}\text{PM (TPY)} &= 1.647 \times 10^{12} \text{ Btu/yr} \times 0.03 \text{ lb/MMBtu} + 2,000 \\ &= 24.71 \text{ TPY}\end{aligned}$$

2. SO₂: The emission factor is based upon the maximum sulfur content of No. 2 distillate fuel oil. The emission factor is 0.5 lb/MMBtu.

Sample calculation: Activity Factor= 1.647×10^{12} Btu/yr

$$\begin{aligned}\text{SO}_2 \text{ (TPY)} &= 1.647 \times 10^{12} \text{ Btu/yr} \times 0.5 \text{ lb/MMBtu} + 2,000 \\ &= 411.75 \text{ TPY}\end{aligned}$$

3. NO_x, CO, VOC: The emission factors are based on emissions achievable with low-NO_x burners, SNCR (or equivalent), and good combustion.

NO_x: 0.12 lb/MMBtu (30-day rolling average)
CO: 0.2 lb/MMBtu (8-hour average)
VOC: 0.03 lb/MMBtu

Sample calculation: Activity Factor= 1.647×10^{12} Btu/yr

$$\begin{aligned}\text{NO}_x \text{ (TPY)} &= 0.15 \text{ lb/MMBtu} \times 1.647 \times 10^{12} \text{ Btu/yr} + 2,000 \\ &= 98.82 \text{ TPY}\end{aligned}$$

4. Hg: The emission factor is obtained from Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and sources, Second Edition EPA publication 450/2-90-011 (1990). From this value a 30 percent reduction is taken to account for the mercury control system. The final emission factor is 2.4×10^{-6} lb/MMBtu.

5. Lead: The emission factor for lead was obtained from Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources, Second Edition EPA publication 450/2-90-011 (1990). The uncontrolled emission factor is 8.90×10^{-6} lb/MMBtu. A removal efficiency of 90% is achievable with an ESP: 0.89×10^{-6} lb/MMBtu.

Sample calculation: Activity Factor = 2.706×10^{12} Btu/yr

$$\text{Lead (TPY)} = 0.89 \times 10^{-6} / 10^6 \times 2.706 \times 10^{12} + 2,000 = 0.0012 \text{ TPY}$$

6. Beryllium: The emission factor was obtained from Estimating Air Toxics Emissions from Oil and Coal Combustion Sources EPA publication EPA-450/2-89-001 (1989). The emission factor is 0.35×10^{-6} lb/MMBtu.

7. Sulfuric Acid Mist: From the EPA Publication AP-42, sulfuric acid mist emissions for boiler's similar to that of the proposed facility, the emissions are estimated to be 3 percent of the sulfur dioxide emissions. The emission factor = $0.03 \times 0.5 \text{ lb/MMBtu} = 0.015 \text{ lb/MMBtu}$.

8. Antimony, Barium, Bromine, Cobalt, Fluoride, Hydrogen Chloride, Molybdenum, Phosphorus, Silver, Thallium, Tin, Zinc, and Zirconium: There are no available emission factors for distillate No. 2 fuel oil in the literature. However, emission factors for these pollutants for firing residual No. 6 fuel oil are available from Emission Assessment of Conventional Stationary Combustion Systems: Volume V, EPA publication EPA-600/7-81-0300c (1981). Use of these factors will provide a conservative set of emission factors for distillate oil. These emission factors are presented as pg/J. The emission factors are converted to lb/MMBtu.

$$\text{pg/J} \times 10^{-12} \text{ g/pg} \times 1,055 \text{ J/Btu} \times 10^6 \text{ Btu/MMBtu} = 2.324 \times 10^{-6} \text{ lb/MMBtu.}$$

The converted emission factor is then reduced by 90 percent to account for ESP system removal, except for bromine, fluoride, and hydrogen chloride which are emitted as gases.

Example: Zinc - $28.8 \text{ pg/J} \times 2.324 \times 10^{-6} \times (1-.90) = 6.69 \times 10^{-6} \text{ lb/MMBtu}$

Antimony:	10	pg/J = 2.32×10^{-6} lb/MMBtu
Barium:	28.8	pg/J = 6.69×10^{-6} lb/MMBtu
Bromine:	3.0	pg/J = 6.97×10^{-6} lb/MMBtu
Cobalt:	50.5	pg/J = 1.17×10^{-5} lb/MMBtu
Fluoride:	2.7	pg/J = 6.27×10^{-6} lb/MMBtu
Hydrogen Chloride:	274	pg/J = 6.37×10^{-4} lb/MMBtu
Molybdenum:	21	pg/J = 4.88×10^{-6} lb/MMBtu
Phosphorus:	25	pg/J = 5.81×10^{-6} lb/MMBtu
Tin:	142	pg/J = 3.30×10^{-5} lb/MMBtu
Zinc:	28.8	pg/J = 6.69×10^{-6} lb/MMBtu

Sample calculation: Activity Factor = 2.706×10^{12} Btu/yr

$$\text{Zinc (TPY)} = 1.647 \times 10^{12} \times 6.69 \times 10^{-6} + 2,000 + 10^6 = 0.0055 \text{ TPY}$$

9. Arsenic, Cadmium, Chromium, Copper, Formaldehyde, Manganese, Nickel, and Selenium: Emission factors were obtained from Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and sources, Second Edition EPA publication 450/2-90-011 (1990). These emission factors reflect ESP control and are reported as lb/10¹² Btu.

Arsenic:	5.0×10^{-7} lb/MMBtu
Cadmium :	1.58×10^{-6} lb/MMBtu
Chromium:	1.39×10^{-5} lb/MMBtu
Chromium ⁺⁶ :	20% of Chromium - 2.78×10^{-6} lb/MMBtu
Copper:	4.2×10^{-5} lb/MMBtu
Formaldehyde:	4.05×10^{-4} lb/MMBtu
Manganese:	3.08×10^{-6} lb/MMBtu
Nickel:	4.76×10^{-5} lb/MMBtu
Selenium:	4.60×10^{-6} lb/MMBtu

Sample calculation: Activity Factor = 1.647×10^{12} Btu/yr

$$\text{Arsenic: } 5.0 \times 10^{-7} \text{ lb/MMBtu} \times 1.647 \times 10^{12} \text{ Btu/yr} + 2,000 = 0.00041 \text{ TPY}$$

10. Dioxins and Furans: No emission factors were available in the literature for dioxins and furans for oil combustion.

11. Ammonia

See calculations for coal--0.048 lb/MMBtu.

C. Bituminous Coal

1. PM, SO₂: The emission factors for PM and SO₂ are based on the NSPS. For PM, the emission factor is 0.03 lb/MMBtu. For SO₂, the emission factor is 1.2 lb/MMBtu.

Sample calculation: Activity Factor = 1.647×10^{12} Btu/yr

$$\begin{aligned}\text{PM (TPY)} &= 1.647 \times 10^{12} \text{ Btu} \times 0.03 \text{ lb/MMBtu} + 2,000 + 10^6 = 24.71 \text{ TPY} \\ \text{SO}_2 \text{ (TPY)} &= 1.647 \times 10^{12} \text{ Btu} \times 1.2 \text{ lb/MMBtu} + 2,000 + 10^6 = 988.2 \text{ TPY}\end{aligned}$$

2. NO_x: The emission factor used is based upon the boiler design and SNCR control system. The emission factor is 0.17 lb/MMBtu, 30-day rolling average.

$$\text{NO}_x \text{ (TPY): } 0.17 \text{ lb/MMBtu} = 140.0 \text{ TPY}$$

3. CO, VOC: The emission factors used are based upon boiler design.

$$\begin{aligned}\text{CO (TPY): } &0.2 \text{ lb/MMBtu (8-hour average)} \\ \text{VOC (TPY): } &0.03 \text{ lb/MMBtu}\end{aligned}$$

4. Hg: The emission factor is obtained from "Mercury Emissions to the Atmosphere in Florida" (KBN, 1992) for a coal fired boiler with an ESP. The average emission factor is 8.4×10^{-6} lb/MMBtu.

5. Sulfuric Acid Mist: From the EPA Publication AP-42, sulfuric acid mist emissions for boiler's similar to that of the proposed facility, the emissions are estimated to be 3 percent of the concurrent sulfur dioxide emissions. The emission factor = $0.03 \times 1.2 \text{ lb/MMBtu} = 0.036 \text{ lb/MMBtu}$.

6. Antimony, Barium, Bromine, Cobalt, Hydrogen Chloride, Fluorides, Molybdenum, Phosphorus, Selenium, Tin, and Zinc: Emission factors were obtained from Emission Assessment of Conventional Stationary Combustion Systems: Volume V EPA publication EPA-600/7-81-0300c (1981). These emission factors were reported as ng/J. The factors were converted to lb/MMBtu. The proposed facility's boilers are similar to the spreader stoker design. From Table 31, uncontrolled emission factors were taken and then a 90% reduction was applied to account for removal by the ESP system for each pollutant except hydrogen chloride, fluorides, and bromine.

$$\begin{aligned}\text{ng/J} \times 1055 \text{ J/Btu} \times 1,000,000 \text{ Btu/MMBtu} \times 10^{-9} \text{ g/ng} \times \text{lb/454 g} \\ = 2.324 \times 10^{-3} \text{ (lb/MMBtu)/(ng/J)}\end{aligned}$$

Sample calculation:

$$\begin{aligned}\text{Antimony} &= 0.15 \text{ ng/J} \times 2.324 \times 10^{-3} \text{ (lb/MMBtu)/(ng/J)} \times (1-.9) \\ &= 3.49 \times 10^{-5} \text{ lb/MMBtu}\end{aligned}$$

Antimony:	0.15 ng/J = 3.49×10^{-5} lb/MMBtu
Barium:	3.2 ng/J = 7.44×10^{-4} lb/MMBtu
Bromine:	0.34 ng/J = 7.90×10^{-4} lb/MMBtu (no control)
Cobalt:	0.31 ng/J = 7.20×10^{-5} lb/MMBtu
Hydrogen Chloride:	33.9 ng/J = 7.90×10^{-2} lb/MMBtu (no control)
Fluoride:	10.3 ng/J = 2.39×10^{-2} lb/MMBtu (no control)
Molybdenum:	0.38 ng/J = 8.83×10^{-5} lb/MMBtu
Phosphorus:	3.7 ng/J = 8.60×10^{-4} lb/MMBtu
Selenium:	0.23 ng/J = 5.34×10^{-5} lb/MMBtu
Tin:	0.38 ng/J = 8.83×10^{-5} lb/MMBtu
Zinc:	1.5 ng/J = 3.49×10^{-4} lb/MMBtu

Sample calculation: Activity Factor = 1.647×10^{12} Btu/yr

$$\text{Antimony: } 3.49 \times 10^{-5} \times 1.647 \times 10^{12} + 2,000 = 0.029 \text{ TPY}$$

7. Arsenic, Beryllium, Cadmium, Chromium, Copper, Formaldehyde, Lead, Manganese, and Nickel: Emission factors were obtained from Estimating Air Toxics Emissions from Oil and Coal Combustion Sources EPA publication EPA-450/2-89-001 (1989). The emission factors are presented by boiler type/control status and presented in units of lb/10¹² Btu. When listed, the boiler type/control status of choice is spreader stoker with ESP. Otherwise, a 90% reduction was made to the uncontrolled value.

Arsenic:	264 lb/10 ¹² Btu (uncontrolled) x (1-.9) = 2.64×10^{-5} lb/MMBtu
Beryllium:	5.9 lb/10 ¹² Btu (ESP) = 5.90×10^{-6} lb/MMBtu
Cadmium:	1.36 lb/10 ¹² Btu (ESP) = 1.36×10^{-6} lb/MMBtu
Chromium:	16.6 lb/10 ¹² Btu (ESP) = 1.66×10^{-5} lb/MMBtu
Chromium ⁺⁶ :	20% of chromium = 3.32×10^{-6} lb/MMBtu
Copper:	171 lb/10 ¹² Btu (ESP) = 1.71×10^{-4} lb/MMBtu
Formaldehyde:	220 lb/10 ¹² Btu (no control with ESP) = 2.20×10^{-4} lb/MMBtu
Manganese:	31 lb/10 ¹² Btu (ESP) = 3.10×10^{-6} lb/MMBtu
Nickel:	1,020 lb/10 ¹² Btu (ESP) = 1.02×10^{-3} lb/MMBtu

Sample calculation: Activity Factor = 1.647×10^{12} Btu/yr

$$\text{Beryllium: } 5.90 \times 10^{-6} \times 1.647 \times 10^{12} + 2,000 = 0.0049 \text{ TPY}$$

8. Ammonia

Maximum NH₃ slip when burning coal will be 65 ppmv, based on vendor information.

Maximum flow rate per boiler = 197,400 acfm.

$$\begin{aligned} \text{NH}_3 &= 2,116.8 \times 197,400 \times 60 \times 17/1,545 + (460 + 350) \times 65/10^6 \\ &= 22.1 \text{ lb/hr per boiler} \end{aligned}$$

$$22.1 \text{ lb/hr} + 460 \times 10^6 = 0.048 \text{ lb/MMBtu}$$

APPENDIX B

**DERIVATIONS OF EMISSION FACTORS FOR BASELINE
EMISSIONS FOR EXISTING FACILITY**

All pollutant emissions are expressed in terms of lb/MMBtu, lb/ton/ or lb/lb steam for bagasse, and in terms of lb/1000 gal for fuel oil. The basis for the emission factors is presented below.

A. BAGASSE

1. PM: Emission factors are determined from annual air operating reports, which provide total steam production and total PM emitted based on PM stack tests and measured steam production. Annual reports did not take into account fuel oil burning, so this is calculated separately, based on AP-42 emission factors. Activity factors for bagasse are equivalent to total steam production multiplied by the Btu contribution of bagasse with respect to total Btu input for steam generation.

For a given boiler:

$$\begin{aligned} & \text{Total lb steam/yr} \times \text{Btu bagasse/Btu total} \times \text{lb PM/lb steam} \\ & \times \text{ton/2,000 lb} = \text{total PM (TPY) bagasse} \end{aligned}$$

where lb PM/lb steam is computed as follows:

$$\text{PM (lb/yr) test} + \text{total steam (lb/yr)} = \text{lb PM/lb steam}$$

Sample calculation:

Boiler No. 4, 1991

$$\begin{aligned} & 77.90 \text{ TPY PM} \times 2,000 \text{ lb/ton} + 419,766,947 \text{ lb/yr Steam} \\ & = 3.7115 \times 10^4 \text{ lb PM/lb steam} \end{aligned}$$

$$\begin{aligned} \text{Btu (bagasse)} &= 82,306 \text{ tons bagasse} \times 2,000 \text{ lb/ton} \times 4250 \text{ Btu/lb bagasse} \\ &= 6.996 \times 10^{11} \text{ Btu bagasse} \end{aligned}$$

$$\begin{aligned} \text{Btu (oil)} &= 284,690 \text{ gal oil} \times 150,000 \text{ Btu/gal oil} \\ &= 0.427 \times 10^{11} \text{ Btu} \end{aligned}$$

$$\text{Btu (total)} = (6.996 + 0.427) = 7.423 \times 10^{11} \text{ Btu}$$

$$\text{Steam (bagasse)} = 419,766,947 \times (6.996/7.423) = 395,620,310 \text{ lb/yr}$$

$$\text{PM (bagasse)} = 3.9562 \times 10^8 \text{ lb steam/yr} \times 3.7115 \times 10^{-4} \text{ lb/lb} + 2,000 = 73.42 \text{ TPY}$$

$$\text{PM (oil)} = 284,690 \text{ gal/yr} \times 27 \text{ lb/1,000 gal} + 2,000 = 3.84 \text{ TPY}$$

$$\text{PM (total)} = 73.42 + 3.84 = 77.26 \text{ TPY}$$

2. SO₂: Industry data indicate an average of 0.006% sulfur (dry basis) and 50% moisture in bagasse. This is equivalent to 0.003%, wet basis. Test data also

indicate SO₂ removal in the wet scrubbers when burning bagasse, estimated at 60%.
The emission factor is:

$$\begin{aligned} &1 \text{ ton bagasse} \times 2,000 \text{ lb/ton} \times 0.00003 \text{ lb S/lb} \times 2 \text{ lb SO}_2/\text{lb S} \times (1-0.60) \\ &= 0.048 \text{ lb/ton.} \end{aligned}$$

Sample calculation: Activity factor = 401,924 tons bagasse/yr

$$\begin{aligned} \text{SO}_2 \text{ (TPY)} &= 0.048 \text{ lb/ton} \times 401,924 \text{ TPY bagasse} \times \text{ton}/2,000 \text{ lb} \\ &= 9.65 \text{ TPY} \end{aligned}$$

3. NO_x: The emission factor used is an average of emission factors taken between industry test data (KBN, 1990) for traveling gate boilers for bagasse and EPA AP-42.

Industry test data (KBN, 1990) range up to 0.33 lb NO_x/MMBtu

EPA-42 : 0.14 lb/MMBtu

$$\text{Average} = (0.33 + 0.14)/2 = 0.235 \text{ lb NO}_x/\text{MMBtu}$$

$$\begin{aligned} \text{Sample calculation: } &401,924 \text{ TPY bagasse} \times 2,000 \text{ lb/ton} \times 4,250 \text{ Btu/lb} \\ &= 3.42 \times 10^6 \text{ MMBtu} \end{aligned}$$

$$\begin{aligned} \text{NO}_x \text{ (TPY)} &= 3.42 \times 10^6 \text{ MMBtu} \times 0.235 \text{ lb/MMBtu} \times \text{ton}/2,000 \text{ lb} \\ &= 401.42 \text{ TPY} \end{aligned}$$

4. CO: The emission factor used is based upon industry test data. The emission factor is 29 lb/ton.

Sample calculation:

$$\begin{aligned} \text{CO (TPY)} &= 401,924 \text{ tons bagasse} \times 29 \text{ lb/ton bagasse} \times \text{ton}/2,000 \text{ lb} \\ &= 5,827.9 \text{ TPY} \end{aligned}$$

5. VOC: The emission factor used is based on a compilation of industry stack test data. The emission factor is 1.02 lb/ton.

Sample calculation:

$$\begin{aligned} \text{VOC (TPY)} &= 401,924 \text{ ton bagasse} \times 1.02 \text{ lb/ton} \times \text{ton}/2,000 \text{ lb} \\ &= 204.98 \text{ TPY} \end{aligned}$$

6. Hg: Bill Patrick, LSU, obtained 17 samples of dead sugar cane leaves in Oct.-Dec, 1991. The average Hg content was 0.068 ppm Hg (dry), or 0.033 ppm at 51.7% moisture. These are considered to be representative of bagasse, which is dead

sugar cane stalks. The resulting emission factor is:

$$2,000 \text{ lb/ton} \times 0.033 \text{ ppm (wet)} = 6.6 \times 10^{-5} \text{ lb/ton (wet)}$$

Sample calculation:

$$\begin{aligned} \text{Hg(TPY)} &= 6.60 \times 10^{-5} \text{ lb/ton} \times 401,924 \text{ TPY} \times \text{ton}/2,000 \text{ lb} \\ &= 0.01326 \text{ TPY} \end{aligned}$$

7. Lead: No emission factor is available for bagasse. Tests conducted at Seminole Kraft Corporation (SKC) in Jacksonville, Florida (1990) provide an emission factor for lead from wood-fired boilers with a wet scrubber. The emission factor is 0.00077 lb/ton.

Sample calculation:

$$\text{Lead (TPY)} = 0.00077 \text{ lb/ton} \times 401,924 \text{ TPY} \times \text{ton}/2,000 \text{ lb} = 0.1547 \text{ TPY}$$

8. Beryllium, Fluoride: No detectable amounts of beryllium were measured during the SKC emission tests on wood-fired boilers in 1990. An emission factor for fluorides is not available for wood- or bagasse-fired boilers.

9. Sulfuric Acid Mist: From EPA Publication AP-42, sulfuric acid mist emissions are equivalent to 3 percent of SO₂ emissions. This factor was used directly to convert total SO₂ emissions into sulfuric acid mist emissions.

B. No. 6 Fuel Oil:

1. PM: The emission factor is taken from EPA AP-42 using a 2.4% sulfur content by weight. This is the sulfur content of oil burned at Osceola.

$$\text{AP-42: } 27 \text{ lb PM}/1,000 \text{ gal}$$

Sample calculation:

1991 Boiler 4: Activity Factor= 284,690 gal

$$\begin{aligned} \text{PM (TPY)} &= 27 \text{ lb}/1,000 \text{ gal} \times 284,690/\text{yr} \times \text{ton}/2,000 \text{ lb} \\ &= 3.84 \text{ TPY} \end{aligned}$$

2. SO₂, NO_x, CO, VOC: The emission factors are based on EPA AP-42.

$$\text{SO}_2: 376.8 \text{ lb}/1,000 \text{ gal} (157 \times 2.4)$$

$$\text{NO}_x: 67 \text{ lb}/1,000 \text{ gal}$$

$$\text{CO: } 5 \text{ lb}/1,000 \text{ gal}$$

VOC: 0.76 lb/1,000 gal

Sample calculation:

All Boilers 1991: Activity Factor = 854,070 gal

$$\text{SO}_2 \text{ (TPY)} = 376.8/1,000 \times 854,070 + 2,000 = 160.91 \text{ TPY}$$

3. Hg: The emission factor is based on average Hg content of No. 6 fuel oil.
The emission factor is 0.00055 lb/1,000 gal

Sample calculation: Activity Factor = 854,070 gallons/yr

$$\begin{aligned} \text{Hg (TPY)} &= 0.00055 \text{ lb/1,000 gal} \times 854,070/\text{yr} \times \text{ton}/2,000 \text{ lb} \\ &= 0.00023 \text{ TPY} \end{aligned}$$

4. Beryllium, Lead: The emission factors are obtained from Toxic Air Pollutant Emission Factors, Second Edition EPA publication EPA-450/2-90-011 (1990).

The emission factors are: Lead = 0.0042 lb/1,000 gal

$$\text{Beryllium} = 0.000038 \text{ lb/1,000 gal}$$

Sample calculation: Activity Factor = 854,070 gallons/yr

$$\begin{aligned} \text{Lead (TPY)} &= 0.0042 \text{ lb/1,000 gal} \times 854,070/\text{yr} \times \text{ton}/2,000 \text{ lb} \\ &= 0.00179 \text{ TPY} \end{aligned}$$

5. Fluoride: The emission factor is obtained from Emissions Assessment of Conventional Stationary Combustion Systems: Volume V EPA Publication EPA 600/7-81-0-003 (1981). The emission factor is 0.0177 lb/1000 gal

Sample calculation: Activity Factor = 854,070 gallons/yr

$$\begin{aligned} \text{Fluoride (TPY)} &= 0.077 \text{ lb/1,000 gal} \times 854,070/\text{yr} \\ &\quad \times \text{ton}/2,000 \text{ lb} = 0.007559 \text{ TPY} \end{aligned}$$

9. Sulfuric Acid Mist: From EPA Publication AP-42, sulfuric acid mist emissions are equivalent to 3 percent of SO₂ emissions.

Sample calculation (1991):

$$\text{Sulfuric Acid Mist (TPY)} = 160.91 \times 0.03 = 4.83 \text{ TPY}$$

C. TOTAL EMISSIONS

Total emissions for each pollutant is the sum of emissions due to bagasse firing and emissions due to fuel oil firing. For PM10, industry test data indicate approximately 90% of PM emissions are PM10:

$$\text{PM}_{10} = \text{PM}(\text{TSP}) \times 0.90$$

Table B-1. Baseline Particulate Emissions for Osceola Farms

No. 6 Oil					Bagasse				
Source Description	Particulate Emission Factor (lb/1000 gal)	Ref	Activity Factor (1000 gal/yr)	Particulate Emissions (TPY)	Particulate Emission Factor (lb PM/lb steam)	Ref	Activity Factor (#steam/yr)	Particulate Emissions (TPY)	Total Particulate Emissions (TPY)
1991									
Boiler No. 1	27	1	0.00	0.00	--	2	0	0.00	0.00
Boiler No. 2	27	1	284.69	3.84	3.87E-04	2	398,440,154	77.01	80.85
Boiler No. 3	27	1	0.00	0.00	3.28E-04	2	360,300,000	59.02	59.02
Boiler No. 4	27	1	284.69	3.84	3.71E-04	2	395,649,629	73.42	77.26
Boiler No. 5	27	1	284.69	3.84	2.54E-04	2	425,929,356	54.15	57.99
Boiler No. 6	27	1	0.00	0.00	2.12E-04	2	492,200,000	52.26	52.26
			854.07	11.53			2,072,519,139	315.86	327.39
1990									
Boiler No. 1	27	1	0.00	0.00	--	2	0	0.00	0.00
Boiler No. 2	27	1	312.41	4.22	3.87E-04	2	342,001,263	66.17	70.39
Boiler No. 3	27	1	0.00	0.00	4.15E-04	2	281,700,000	58.43	58.43
Boiler No. 4	27	1	312.41	4.22	5.92E-04	2	329,265,855	97.53	101.75
Boiler No. 5	27	1	312.41	4.22	3.95E-04	2	424,495,321	83.87	88.09
Boiler No. 6	27	1	0.00	0.00	2.95E-04	3	470,339,917	69.38	69.38
			937.23	12.65			1,847,802,356	375.38	388.04
Average									
Boiler No. 1	-	-	-	0.00	-	-	-	0.00	0.00
Boiler No. 2	-	-	-	4.03	-	-	-	71.59	75.62
Boiler No. 3	-	-	-	0.00	-	-	-	58.73	58.73
Boiler No. 4	-	-	-	4.03	-	-	-	85.48	89.51
Boiler No. 5	-	-	-	4.03	-	-	-	69.01	73.04
Boiler No. 6	-	-	-	0.00	-	-	-	60.82	60.82
								Total	357.71

References/Notes:

1. Compilation of Air Pollutant Emission Factors AP-42, Section 1.3 oil sulfur content 2.4% by weight
2. Emission factors from stack tests and steam production during tests.

Table B-2. Computation of Baseline PM Emission Factors for Osceola Farms from stack tests

Blr #	1991 data			1990 data		
	Total Steam (#/yr)	PM emis (#/yr)	Emission Factor (#PM/#steam)	Total Steam (#/yr)	PM emis (#/yr)	Emission Fa (#PM/#stea
1	0	0	--	0	0	--
2	422,600,000	163,360	3.87E-04	366,600,000	141,860	3.87E-04
3	360,300,000	118,040	3.28E-04	281,700,000	116,860	4.15E-04
4	419,800,000	155,800	3.71E-04	353,800,000	209,600	5.92E-04
5	448,100,000	113,940	2.54E-04	449,400,000	177,580	3.95E-04
6	492,200,000	104,520	2.12E-04	470,339,917	138,760	2.95E-04

Table B-3. Activity Factors used in PM emission factor determination for Osceola Farms

Blr #	Bagasse		Oil		Total Btu	Steam Production (lbs)		
	tons	Btu	gals	Btu		Total	Bagasse	Oil
1991								
1	0	0	0	0	0	--	--	--
2	82,854	7.04E+11	284,690	4.27E+10	7.47E+11	422,600,000	398,440,154	24,159,846
3	70,652	6.01E+11	0	0	6.01E+11	360,300,000	360,300,000	0
4	82,306	7.00E+11	284,690	4.27E+10	7.42E+11	419,800,000	395,649,629	24,150,371
5	96,517	8.20E+11	284,690	4.27E+10	8.63E+11	448,100,000	425,929,356	22,170,644
6	82,306	7.00E+11	0	0	7.00E+11	492,200,000	492,200,000	0
1990								
1	0	0	0	0	0	--	--	--
2	76,650	6.52E+11	312,410	4.69E+10	6.98E+11	366,600,000	342,001,263	24,598,737
3	58,960	5.01E+11	0	0	5.01E+11	281,700,000	281,700,000	0
4	73,990	6.29E+11	312,410	4.69E+10	6.76E+11	353,800,000	329,265,855	24,534,145
5	93,970	7.99E+11	312,410	4.69E+10	8.46E+11	449,400,000	424,495,321	24,904,679
6	98,350	8.36E+11	0	0	8.36E+11	470,339,917	470,339,917	0

Notes:

Heating value of No. 6 Fuel Oil =150,000 Btu/gal

Heating value of bagasse = 4,250 Btu/lb

Table B-4. Baseline SO2 Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total SO2 Emissions (TPY)
	Sulfur Dioxide Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual SO2 Emissions (TPY)	Sulfur Dioxide Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual SO2 Emissions (TPY)	
1990	376.8	1	937.23	176.57	0.048	2	401,924	9.65	186.22
1991	376.8	1	854.07	160.91	0.048	2	414,635	9.95	170.86
Average				168.74				9.80	178.54

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3, and a oil sulfur content of 2.4% by weight.
2. Based on sulfur content for bagasse of 0.006% by weight, dry basis, 50% moisture as fired, and a control system efficiency of 60%. Activity factor is based on wet bagasse fired.

Table B-5. Baseline NOx Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total NOx Emissions (TPY)
	Nitrogen Oxides Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual NOx Emissions (TPY)	Nitrogen Oxides Emission Factor (lb/MMBtu)	Ref.	Activity Factor (MMBtu/yr)	Annual NOx Emissions (TPY)	
1990	67	1	937.23	31.40	0.235	2	3.42E+06	401.42	432.82
1991	67	1	854.07	28.61	0.235	2	3.52E+06	414.12	442.73
Average				30.00				407.77	437.77

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3.
2. Based on average between AP-42 emission factors and industry test data for bagasse fired boilers.

Table B-6. Baseline CO Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total CO Emissions (TPY)
	Carbon Monoxide Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual CO Emissions (TPY)	Carbon Monoxide Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual CO Emissions (TPY)	
1990	5		937.23	2.34	29	2	401,924	5,827.9	5,830.2
1991	5		854.07	2.14	29	2	414,635	6,012.2	6,014.3
Average			2.24					5,920.1	5,922.3

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3.
2. Based on compilation of stack test data for bagasse boilers.

Table B-7. Baseline VOC Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total VOC Emissions (TPY)
	VOC Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual VOC Emissions (TPY)	VOC Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual VOC Emissions (TPY)	
1990	0.76	1	937.23	0.36	1.02	2	401,924	204.98	205.34
1991	0.76	1	854.07	0.32	1.02	2	414,635	211.46	211.79
Average				0.34				208.22	208.56

References/Notes:

1. Compilation of Air Pollutant Emission Factors, AP-42, Section 1.3.
2. Based on compilation of stack test data for bagasse boilers.

Table B-8. Baseline Mercury Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total Hg Emissions (TPY)
	Hg Emission Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Hg Emissions (TPY)	Hg Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Hg Emissions (TPY)	
1990	0.00055	1	937.23	0.00026	6.6E-05	2	401,924	0.01326	0.01352
1991	0.00055	1	854.07	0.00023	6.6E-05	2	414,635	0.01368	0.01392
Average				0.00025				0.01347	0.01372

References/Notes:

1. Based on average Hg content of No. 6 fuel oil.
2. Based on a mercury content of dead cane leaves of 0.068 ppm (dry) and 50% moisture. Activity factor is based on wet bagasse.

Table B-9. Baseline Beryllium Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total Beryllium Emissions (TPY)
	Beryllium Activity Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Beryllium Emissions (TPY)	Beryllium Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Beryllium Emissions (TPY)	
1990	3.75E-05	1	937.23	0.000018	0	2	401,924	0	0.000018
1991	3.75E-05	1	854.07	0.000016	0	2	414,635	0	0.000016
Average				0.000017				0	0.000017

References/Notes:

1. Toxic Air Pollutant Emission Factors (EPA-450/2-90-011) (1990).
2. Emission tests for Seminole Kraft (1990) and TAPPI Proceedings (1990).

Table B-10. Baseline Fluoride Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total Fluoride Emissions (TPY)
	Fluoride Activity Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Fluoride Emissions (TPY)	Fluoride Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Fluoride Emissions (TPY)	
1990	0.0177	1	937.23	0.008294	0.0	2	401,924	0.0	0.00829
1991	0.0177	1	854.07	0.007559	0.0	2	414,635	0.0	0.00756
Average				0.007927				0.0	0.00793

References/Notes:

1. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources (EPA-600/7-81-0-003) (1981).
2. No emission factor for bagasse or wood is available.

Table B-11. Baseline Lead Emissions for Osceola Farms

Year	No. 6 Fuel Oil				Bagasse				Total Flouride Emissions (TPY)
	Lead Activity Factor (lb/1000 gal)	Ref.	Activity Factor (1000 gal/yr)	Annual Lead Emissions (TPY)	Lead Emission Factor (lb/ton)	Ref.	Activity Factor (TPY)	Annual Lead Emissions (TPY)	
1990	0.0042	1	937.23	0.00197	0.000770	2	401,924	0.15474	0.15671
1991	0.0042	1	854.07	0.00179	0.000770	2	414,635	0.15963	0.16143
Average				0.00188				0.15719	0.15907

References/Notes:

1. Toxic Air Pollutant Emission Factors (EPA-450/2-90-011) (1990).
2. No data is available for bagasse; based on testing and on wood fired boilers at Seminole Kraft Corp. (1990).

Table B-12. Summary of NO_x Emission Tests Performed on Bagasse Boilers in Florida

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate ^a (TPH wet)	NO _x Emissions		
						lb/hr	lb/MMBtu	lb/ton,wet
<u>Atlantic Sugar Association</u>								
Boiler 3	Horseshoe	03/19/80	92,868	160.2	22.25	27.7	0.17	1.24
Boiler 4	Horseshoe	03/18/80	91,833	158.4	22.00	31.8	0.20	1.45
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	25.9	0.13	0.93
Boiler 5	Traveling Grate	03/21/83	98,000	183	25.42	15.7	0.09	0.62
Boiler 5	Traveling Grate	03/21/83	108,000	201	25.42	28.1	0.14	1.01
Boiler 5	Traveling Grate	03/21/83	107,000	200	27.78	32.0	0.16	1.15
Boiler 5	Traveling Grate	03/21/83	107,000	199	27.64	29.9	0.15	1.08
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	9.7	NA	NA
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	7.7	NA	NA
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	6.4	NA	NA
Boiler 5	Traveling Grate	02/28/88	NA	NA	NA	27.7	NA	NA
Boiler 5	Traveling Grate	01/11/89	119,500	219.9	30.54	18.3	0.08	0.60
<u>Okeelanta</u>								
Boiler 10	Horseshoe	04/10/80	97,667	168.5	23.40	17.7	0.11	0.76
<u>Osceola Farms</u>								
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	16.8	0.06	0.42
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	7.9	0.03	0.20
Boiler 6	Traveling Grate	12/09/86	150,000	290	40.28	12.8	0.04	0.32
<u>Sugar Cane Growers Cooperative^b</u>								
Boiler 1	Traveling Grate	03/20/80	81,176	118.5	16.46	38.7	0.33	2.35
Boiler 2	Traveling Grate	03/20/80	94,500	137.9	19.15	37.3	0.26	1.84
Boiler 8	Traveling Grate	02/04/83	246,429	414	57.50	43.1	0.10	0.75
Boiler 8	Traveling Grate	02/04/83	243,250	406	56.39	29.2	0.07	0.52
Boiler 8	Traveling Grate	02/04/83	254,211	425	59.03	32.3	0.08	0.55
Boiler 8	Traveling Grate	01/27/89	248,000	425.2	39.81 ^c	117.9	0.28	2.96
Boiler 8	Traveling Grate	01/27/89	251,408	431.0	40.36 ^c	118.8	0.28	2.94
Boiler 8	Traveling Grate	01/27/89	249,375	427.5	40.03 ^c	117.7	0.28	2.94
<u>U.S. Sugar - Bryant</u>								
Boiler 2	Vibrating Grate	02/26/80	155,000	267.4	37.14	14.9	0.06	0.40
Boiler 5	Vibrating Grate	02/03/89	253,253	566.2	80.95 ^d	85.0	0.15	1.05
Boiler 5	Vibrating Grate	02/03/89	247,612	554.2	79.55 ^d	71.6	0.13	0.90
Boiler 5	Vibrating Grate	02/03/89	253,881	568.2	81.33 ^d	79.7	0.14	0.98
<u>U.S. Sugar - Clewiston</u>								
Boiler 1	Vibrating Grate	02/28/80	215,000	370.9	51.51	26.9	0.07	0.52
Boiler 4	Traveling Grate	12/23/85	262,500	561.4	76.2 ^d	92.9	0.17	1.10
Boiler 4	Traveling Grate	12/23/85	266,000	562.7	76.3 ^d	70.4	0.13	0.83
Boiler 4	Traveling Grate	12/23/85	251,407	532.3	72.4 ^d	58.2	0.11	0.73

Note: lb/hr = pounds per hour.
 lb/MMBtu = pounds per million British thermal units.
 lb/ton = pounds per ton.
 MMBtu/hr = million British thermal units per hour.
 NA = not available.
 TPH = tons per hour.

^a Assumed 3,600 Btu/lb average heat content for wet bagasse.

^b Heat input and NO_x emissions due to oil burning excluded.

^c Combination of residue/oil firing; oil firing constituted less than 7 percent of total heat input. Average heating value of wet residue assumed to be 5,340 Btu/lb.

^d Based on actual reported data.

Table B-13. Summary of VOC Emission Tests Performed on Bagasse Boilers in Florida

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate ^a (TPH wet)	VOC Emissions		
						lb/hr	lb/MMBtu	lb/ton,wet
<u>Atlantic Sugar</u>								
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	14.3	0.07	0.51
Boiler 5	Traveling Grate	03/21/83	98,000	183	25.42	14.6	0.08	0.57
Boiler 5	Traveling Grate	03/21/83	108,000	201	27.92	14.5	0.07	0.52
Boiler 5	Traveling Grate	02/20/87	NA	NA	NA	20.0	NA	NA
Boiler 5	Traveling Grate	02/28/88	NA	NA	NA	34.3	NA	NA
Boiler 5	Traveling Grate	01/11/89	119,500	219.9	30.54	25.2	0.12	0.82
<u>Osceola Farms</u>								
Boiler 6	Traveling Grate	12/18/86	160,000	310	43.06	79.0	0.25	1.83
Boiler 6	Traveling Grate	12/18/86	160,000	310	43.06	49.0	0.16	1.14
<u>Sugar Cane Growers Cooperative</u>								
Boiler 8	Traveling Grate	02/04/83	246,429	414	57.50	13.9	0.03	0.24
Boiler 8	Traveling Grate	02/04/83	243,250	406	56.39	26.8	0.07	0.48
Boiler 8	Traveling Grate	02/04/83	254,211	425	59.03	88.1	0.21	1.49
Boiler 8 ^b	Traveling Grate	01/06/89	NA	425.2	39.81	35.8	0.08	0.90
						5.41 ^c	0.01	0.14
Boiler 8 ^b	Traveling Grate	01/06/89	NA	431.0	40.36	36.2	0.08	0.90
						12.7 ^c	0.03	0.32
Boiler 8 ^b	Traveling Grate	01/06/89	NA	427.5	40.03	111.4	0.26	2.78
						21.5 ^c	0.05	0.54
<u>U.S. Sugar - Bryant</u>								
Boiler 5	Vibrating Grate	02/03/89	253,253	566.2	80.95 ^d	102.8	0.18	1.27
Boiler 5	Vibrating Grate	02/03/89	253,881	568.2	81.33 ^d	116.3	0.20	1.43
<u>U.S. Sugar - Clewiston</u>								
Boiler 4	Traveling Grate	12/23/85	262,500	561.4	76.2 ^d	104.4	0.19	1.37
Boiler 4	Traveling Grate	12/23/85	266,000	562.7	76.3 ^d	71.0	0.13	0.93
Boiler 4	Traveling Grate	12/23/85	251,407	532.3	72.4 ^d	120.2	0.23	1.66

Note: lb/hr = pounds per hour.
 lb/MMBtu = pounds per million British thermal units.
 lb/ton = pounds per ton.
 MMBtu/hr = million British thermal units per hour.
 NA = not available.
 TPH = tons per hour.

^a Calculated from reported heat input rate, assumed 3,600 Btu/lb average heat content for wet bagasse. Average heat value for wet residue is 5,340 Btu/lb.

^b Residue was used as fuel source. Average heat value for wet residue is 5,340 Btu/lb.

^c Sample analyzed by another analytical laboratory.

^d Based on actual reported data.

Table B-14. Summary of CO Emission Tests Performed on Bagasse Boilers in Florida Using EPA Method 10

Unit	Boiler Type	Date	Steam Rate (lb/hr)	Heat Input Rate (MMBtu/hr)	Bagasse Burning Rate ^a (TPH wet)	CO Emissions		
						lb/hr	lb/MMBtu	lb/ton,wet
U.S. Sugar - Bryant								
Boiler 5	Vibrating Grate	02/16/89	256,928	577.0	80.14	2,586.9	4.48	32.28
Boiler 5	Vibrating Grate	02/17/89	249,228	561.0	77.92	2,658.0	4.74	34.11
Boiler 5	Vibrating Grate	02/17/89	249,480	562.0	78.06	1,693.3	3.01	21.69
Osceola Farms								
Boiler 3	Traveling Grate	01/17/89	NA	NA	NA	NA	3.07	22.10
Boiler 3	Traveling Grate	12/05/89	NA	NA	NA	NA	0.81	5.83
Boiler 3	Traveling Grate	01/24/90	NA	NA	NA	NA	3.14	22.61
Boiler 6	Traveling Grate	01/16/89	NA	NA	NA	NA	5.42	39.02
Boiler 6	Traveling Grate	11/15/89	NA	NA	NA	NA	5.48	39.46
Boiler 6	Traveling Grate	02/02/90	NA	NA	NA	NA	5.93	42.70

Note: lb/hr = pounds per hour.
 lb/MMBtu = pounds per million British thermal units.
 lb/ton = pounds per ton.
 MMBtu/hr = million British thermal units per hour.
 NA = not available.
 TPH = tons per hour.

^a Calculated from reported heat input rate, assumed 3,600 Btu/lb average heat content for wet bagasse.

APPENDIX C
ZONING CONDITIONS

SEP-11-92 FRI 15:41 OKEELANTA CORP ADMIN

Board of County Commissioners

County Administrator

Karen T. Marcus, Chair
Carole Phillips, Vice Chair
Carol A. Roberts
Carol J. Elmquist
Mary McCarty
Ken Foster
Maude Ford Lee

Robert Weisman

Department of Planning, Zoning & Building



RECEIVED

August 3, 1992

SEP 02 1992

Gary Brandenburg, Esq.
Carlton, Field, Ward, Emmanuel,
Smith & Culter, PA
P. O. Box 150
West Palm Beach, FL 33402

Carlton Fields - West Palm Beach
Gary M. Brandenburg

RE: PETITION NO. 92-13 - SPECIAL EXCEPTION
OSCEOLA FARMS COMPANY

Dear Mr. Brandenburg:

At the Public Hearing on July 30, 1992, the Board of County Commissioners of Palm Beach County, Florida, officially approved your petition as advertised, subject to the attached list of tentative conditions. Please notify your Project Manager, in writing, within five (5) days if you believe there are any errors.

The next two deadlines for site plan certification are 12:00 noon, August 5, 1992, and 12:00 noon, August 17, 1992, for the August 31, 1992, and September 14, 1992, meetings, respectively. Site plan certification meetings commence at 9:00 a.m. in the Conference Room at 3400 Belvedere Road, West Palm Beach, Florida. The following documents must be submitted to this office before 12:00 noon on the deadline specified, for your plan to be considered at the next meeting:

1. Revised master/site plan upon which an exact copy of the Board approved conditions is shown. Site plan certification application is required with all petitions approved by the Board of County Commissioners.
2. Unity of Title/Control, Cross Access Agreement, or any other legal document in need of review for legal sufficiency.
3. Board of Adjustment variance relief, if required.
4. A Certificate of Concurrence or a Certificate of Exemption.

Should you have any questions or need additional assistance, please contact your Project Manager at 233-5034.

Very truly yours,
Roxanne M. Manning
Roxanne M. Manning, Zoning Director

RMM/bjw
Attachment

cc: Petition File, Project Manager, Ann Waters, K. C. Collette, R. Wheelihan, J. Choban, S. Hardy-Miller, D. Beasley, J. Dumas, J. MacGillis, L. Monroe, Minutes Department, J. Crawford, Barbara Bobsein

"An Equal Opportunity - Affirmative Action Employer"

PETITION 92-13

APPROVAL OF THE PETITION IS SUBJECT TO THE FOLLOWING CONDITIONS:

Staff recommends the following conditions:

A. AIR QUALITY

1. Petitioner shall:

- a. Prior to initial start up, install all air pollution control devices and processes required by the Florida Department of Environmental Regulation (DERM), the United States Environmental Protection Agency (EPA), and as described in the environmental report attached hereto and made a part hereof (Exhibit A) to include, but not be limited to:
 - (1) an electrostatic precipitator, designed for at least 98% removal of particulate matter or equivalent;
 - (2) a thermal D-NOx system designed for at least 40% removal of oxides of nitrogen, or equivalent; and
 - (3) an activated carbon injection system for control of mercury emissions, or equivalent.
- b. Continuously monitor and record exhaust gas opacity, oxides of nitrogen, and carbon monoxide.
- c. Test stack emissions according to DER and EPA standards at least once every six months for particulate matter, oxides of nitrogen, carbon monoxide, sulfur dioxide, lead, mercury and volatile organic compounds for the first two years of operation. If the test results for the first two years of operations indicate the facility is operating in compliance with the terms of approval and of applicable permits and regulations, the test will thereafter occur as required by the respective DER and EPA permits, with the exception that stack emissions will be tested annually for mercury. In the event the results of the first two years of testing show non-compliance, then the frequency of testing shall continue to occur once every six months until the facility achieves a sustained two-year period of compliance.
- d. Not exceed the total actual annual emissions from the existing boilers and those currently permitted for construction at this facility. Except for particulate matter and sulfur dioxide, the following figures represent the best available estimates for the actual current emissions. These emissions, in tons per year, by pollutant, are:
 - (1) Particulate Matter: 311.3
 - (2) Oxides of Nitrogen 478.9
 - (3) Carbon Monoxide: 5,895.4
 - (4) Volatile Organic Compounds: 218.1
 - (5) Mercury: 0.0141
 - (6) With regard to sulfur dioxide emissions, the following conditions shall apply:
 - (a) If used, coal shall be of the low sulfur variety, and shall not exceed 0.7% sulfur by weight.

- (b) Fuel oil shall be limited to low sulfur No. 2 distillate oil and shall not exceed 1% sulfur by weight.
- (c) Coal consumption shall not exceed 25% of the total heat input in any calendar quarter.

(Paragraphs (d) through (h) apply to total sulfur dioxide emissions for the combined facilities of petitions 92-13 and 92-14.)

- (d) Shall not exceed the current emissions of the proposed project (an average of 1000 tons of sulfur dioxide. If the life of the project exceeds thirty years, the total allowable lifetime emissions will be adjusted proportionately.)
- (e) For the case that the Palm Beach County government makes available 200,000 tons of biomass fuel per year to the cogeneration facilities in Petitions 92-13 and 92-14, under the same terms and conditions as those in the existing Okeelanta/Palm Beach Solid Waste Authority Wood-waste Agreement, the petitioner shall:
 - 1) not exceed 1500 tons of sulfur dioxide for that year.
 - 2) not exceed an average of 1300 tons of sulfur dioxide for each five year incremental period.
- (f) For the case that the Palm Beach County government cannot make available the 200,00 tons of biomass fuel per year to the cogeneration facilities in Petitions 92-13 and 92-14, the petitioner shall:
 - (1) not exceed 1700 tons of sulfur dioxide for that year.
 - (2) not exceed an average of 1500 tons of sulfur dioxide for each ten year incremental period.
- (g) The allowable average sulfur dioxide emissions for the five and ten year incremental periods described above shall be calculated on a weighted average for any period in which both cases occur (years in which biomass is made available/years in which biomass is not made available.)
- (h) Sulfur dioxide emissions shall include all emissions from the proposed projects in Petitions 92-13 and 92-14 and the currently existing boilers at the Okeelanta and Osceola facilities if in operation during initial project operation.

- e. Employ all methods to control unconfined dust and particulate emissions, required by local, state and/or federal agencies.
 - f. Request in all applications to DER and EPA that the above conditions become part of the corresponding permits. (HEALTH)
2. During land clearing and site preparation, wetting operations or other soil treatment techniques appropriate for controlling unconfined particulates, including grass seeding and mulching of disturbed areas, shall be undertaken and implemented by the Petitioner to comply with state and federal air standards. (ZONING - Health)
 3. With the exception of clearing for access roads, survey lines, construction trailers, equipment staging areas, fencing, and specific building sites, construction shall commence within 90 days after completion of clearing and grading. Any cleared zones or areas not necessary to the operation of the site shall be planted in grass within 90 days after establishment of finished grade. (ZONING)
 4. The petitioner shall comply at all times with the requirements of all permits issued by all agencies having jurisdiction over the facility. (HEALTH - ERM)

B. BUILDING AND SITE DESIGN

1. Maximum total floor area shall be limited to 10% of the total lot area of the subject property. (BUILDING - Zoning)
2. Prior to site plan certification, the site plan shall be amended to indicate a maximum five (5) acre building envelope on the site and the square footage to be contained therein. All construction and development of the principal structure and accessory facilities shall occur within this envelope. All accessory uses indicated on the site plan outside of the building envelope shall be subject to the requirements and regulations of Section 402.7(E)2(b) (Site Plan Review Committee Powers and Standards of Review). Uses and building locations within the envelope shall not be subject to this requirement. (ZONING)

C. ENVIRONMENTAL RESOURCES MANAGEMENT

1. Plans for all underground and above ground storage tanks must be approved by the Department of Environmental Resources Management prior to installation. The petitioner shall perform all necessary preventative measures to reduce the chances of contamination of the groundwater. Double walled tanks and piping with corrosion protection or their equivalent shall be a part of those measures. (BUILDING-ERM)
2. Secondary containment for stored Regulated Substances, including but not limited to fuels, oils, solvents, or other hazardous chemicals, is required. Department of Environmental Resources Management staff are willing to provide guidance on appropriate protective measures. (BUILDING-ERM)
3. All new excavated lakes shall possess a littoral shelf area. A littoral shelf shall be an area with a slope not greater six (6) feet horizontal to one (1) foot vertical, ranging in depth from ordinary high water (OHW) or the controlled water level (CWL) to four feet below OHW or

CWL. A minimum of 30% of the surface area of all lakes shall be planted with native aquatic vegetation on a minimum of three foot centers.

- a. A littoral shelf planting plan and maintenance plan shall be submitted to the Department of Environmental Resources Management concurrent with Site Plan Review application and approved by ERM prior to Site Plan certification. This information shall also be provided on a mylar for the Zoning Division as part of the site plan application. (ERM)
- b. Prior to the issuance of a Certificate of Occupancy and within three working days of the completion of littoral plantings ERM shall be notified. This planting shall not be credited as compensation required by wetland permits. (BUILDING-ERM)

D. EXOTIC SPECIES

1. Areas disturbed as a result of the construction of the cogeneration facility and transmission lines shall be continually maintained to be free of Brazilian Pepper, Australian Pine and Melaleuca. (ZONING)

E. ENGINEERING

1. The Developer shall provide discharge control and treatment for the stormwater runoff in accordance with all applicable agency requirements in effect at the time of the permit application. However, at a minimum, this development shall retain onsite the stormwater runoff generated by a three (3) year-one (1) hour storm with a total rainfall of 3 inches as required by the Permit Section, Land Development Division. The drainage system shall be maintained in an acceptable condition as approved by the County Engineer. In the event that the drainage system is not adequately maintained as determined by the County Engineer, this matter will be referred to the Code Enforcement Board for enforcement (COUNTY ENGINEER).
2. If required by the County Engineer or the South Florida Water Management District the Developer shall design the drainage system such that drainage from those areas which may contain hazardous or undesirable waste shall be separate from stormwater runoff from the remainder of the site (COUNTY ENGINEER).

F. HEALTH

1. Potable water supply for the proposed project is to be provided by a reverse osmosis non-transient non-community water supply system in accordance with Chapter 17-550 & 17-555, F.A.C. (HEALTH)
2. Sewage treatment and disposal for the referenced project is to be provided by one wastewater treatment plant in accordance with Chapter 17-600's F.A.C. All existing septic tank systems shall be abandoned in accordance with applicable codes. (HEALTH)
3. The industrial waste stream generated by this site shall be disposed of in accordance with all applicable Florida DER regulations. (HEALTH)

4. Cogeneration boiler fuels shall be limited to Biomass, as defined in Condition K.9. and fossil fuels. The use of fossil fuels shall be limited in accordance with conditions A.1.d.(6)(a), A.1.d.(6)(b) and A.1.d.(6)(c). The use of Biomass Wastes shall include provisions for the substantial exclusion of painted and chemically treated wood, household garbage, toxic or hazardous materials or wastes and special wastes. This specification must be reviewed and approved by the Palm Beach County Public Health Unit prior to site plan approval. (HEALTH)
5. All fly ash and bottom ash from the facility which is produced during any period in which fossil fuels are used, and thereafter for a reasonable time shall be segregated and managed as set forth in the ash management plan. (HEALTH)
6. Prior to site plan approval, a detailed ash management plan shall be submitted by the petitioner and approved by the Palm Beach County Public Health Unit. This plan must detail contingencies plans, testing and monitoring of the ash, ash handling and disposal methods, planned spreading locations and identification of environmental impacts and proposed measures for mitigating these impacts. (HEALTH)
7. Prior to site plan approval of the operation of the facility, a detailed fuel management plan shall be submitted and approved by the Palm Beach County Public Health Unit. This plan shall detail location, size, handling procedures, transportation, dust control and fire protection. (HEALTH)
8. Prior to site plan approval, the petitioner shall identify all liquid waste streams and provide a complete physical and chemical characterization of the waste streams which shall include, at a minimum, the following information:
 - a. A description of the source or process associated with the waste stream.
 - b. Volume and flow rates.
 - c. Physical parameters including temperature, pH, and total dissolved solids.
 - d. Expected concentrations of pollutants or contaminants, including but not limited to, Nitrogen, Phosphorous and other nutrients, mercury, lead and other trace metals, volatile or semivolatile organic compounds, etc.
 - e. A description and detail of any treatment system utilized.
 - f. A description of the disposal or reuse method and identification of all points of discharge. (HEALTH)
9. Prior to site plan approval, a detailed domestic wastewater management plan shall be submitted and approved by the Palm Beach County Public Health Unit. (HEALTH)

10. Prior to site plan approval, a detailed storm water management plan shall be submitted by the petitioner to the South Florida Water Management District (SFWMD) and Palm Beach County Public Health Unit for review and approval. Staff shall coordinate its review with the SFWMD. (HEALTH)
11. Prior to site plan approval, a detailed industrial wastewater management plan must be submitted to the Department of Environmental Regulation (DER) and the Palm Beach County Public Health Unit for review and approval. Staff shall coordinate its review with the DER. (HEALTH)
12. Prior to site plan approval, all applicable environmental permits or applications for permits must be obtained or submitted. (HEALTH)

G. LANDSCAPING

1. Prior to site plan certification, the petitioner shall submit a Landscape Betterment Plan for review and approval by the Zoning Division. The Landscape Betterment Plan shall demonstrate conformance to all Landscape Code requirements and conditions of approval. (ZONING)
2. As an alternative, the petitioner may landscape the site and provide off-site improvements in accordance with the Unified Land Development Code, upon adoption. (ZONING)

H. LIGHTING

1. All outdoor lighting used to illuminate the premises and identification signs shall be of low intensity, shielded and directed downward. (BUILDING - CODE ENF)

I. PARKING

1. Vehicle parking shall be limited to the parking areas designated on the approved site plan. No parking of vehicles shall be permitted in landscaped areas, right-of-way or interior drives. (CODE ENF)

J. TRANSMISSION LINES

1. All transmission lines required by this facility are to be constructed in accordance with the National Electric Safety Code. (BUILDING)
2. All transmission lines leaving the site and required by this facility shall not exceed 138 KV. (BUILDING)

K. USE LIMITATIONS

1. Use of the site shall be limited as follows:

Land Area	50.00 acres
Total Floor Area	217,800 square feet
Maximum Floor Area	10%
Electrical Production	50 mega watt maximum
Fuel Yard	35 acre max. net land area
2. Prior to site plan certification, the site plan shall be amended to indicate the location of a truck/vehicle wash facility. This wash facility shall utilize a 100% water recycling system. (ZONING - BUILDING)

3. There shall be no repair or maintenance of vehicles on site. (CODE ENF)
4. No outside storage of disassembled vehicles, or parts thereof, shall be permitted on site. (CODE ENF)
5. The maximum height, from grade to highest point, for all fuel storage areas shall not exceed fifty (50) feet. (BUILDING)
6. Onsite storage shall be contained within the area designated on Exhibit 48 and shall be processed and stored in a manner which controls fugitive and dust particulate emissions. (CODE ENF)
7. All vehicles utilizing public rights-of-way to carry biomass waste (i.e. vegetative matter) to the site shall be equipped, at a minimum, with covering or screens over top of the open bed of the vehicle to prevent the loss of material during transportation to the facility. (CODE ENF)
8. The storage of fuel on site shall be limited to the areas designated on the certified site plan and shall be limited to the storage of bagasse and biomass waste only. (CODE ENFORCEMENT)
9. "Biomass Waste", as referred to herein, shall mean bagasse, vegetative and woody matter, including material resulting from landscaping, maintenance, land clearing operations, clean wood, cellulose material, tree and shrub trimmings, grass clippings, palm fronds, trees, tree stumps, wood from land development operations, clean wood debris from demolition operations; it shall not include trash, garbage or sludge (FAC 17-701), biohazardous waste (17-712 FAC), or biological waste (17-712 FAC).
10. The existing boiler facilities shall be abandoned within three (3) years of commercial start up of the cogeneration facility and no later than January 1, 1999. The existing boilers and new facilities shall not be operated at the same time. (MONITORING/CODE ENFORCEMENT)

L. WATER SUPPLY

1. Construction shall not commence on the project site until it has been demonstrated to the satisfaction of the South Florida Water Management District that an acceptable and sustainable supply of water during drought periods is available to serve the project over and above that necessary to serve already approved development. (BUILDING - SFWMD)
2. The petitioner shall utilize all drought-tolerant plants in landscaping on the subject property. (ZONING)
3. The petitioner shall use water-saving plumbing fixtures and other water conserving devices in restrooms and employee locker rooms, as specified in the Water Conservation Act, Section 553.14, F.S.. (BUILDING)

M. COMPLIANCE

1. As provided in the Palm Beach County Zoning Code, Sections 400.2 and 402.6, failure to comply with any of these conditions of approval at any time may result in:

- a. The denial or revocation of a building permit; the issuance of a stop work order; the denial of a Certificate of Occupancy on any building or structure; or the denial or revocation of any permit or approval for any developer-owner, commercial-owner, lessee, or user of the subject property; and/or
 - b. The revocation of the Special Exception and any zoning which was approved concurrently with the Special Exception as well as any previously granted certifications of concurrency or exemptions therefrom; and/or
 - c. A requirement of the development to conform with updated standards of development, applicable at the time of the finding of non-compliance, or the addition or modification of conditions reasonably related to the failure to comply with existing conditions. (MONITORING)
2. Appeals of any departmental-administrative actions hereunder may be taken to the Palm Beach County Board of Adjustment or as otherwise provided in the Palm Beach County Zoning Code. Appeals of any revocation of Special Exception, Rezoning, or other actions based on a Board of County Commission decision, shall be by petition for writ of certiorari to the Fifteenth Judicial Circuit. (MONITORING)

APPENDIX D

**APPLICATION TO OPERATE/CONSTRUCT
AIR POLLUTION SOURCES**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION



\$7,500 pd.
9-30-92
Recpt. #180799

AC50-219795
PSO-FL-197

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Steam Generating Units ☒ New¹ ☐ Existing¹APPLICATION TYPE: ☒ Construction ☐ Operation ☐ ModificationCOMPANY NAME: Sol-Energy, Inc. COUNTY: Palm BeachIdentify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) Boilers No. 1 and No. 2SOURCE LOCATION: Street U.S. 98 and Hatton Highway City PahokeeUTM: East 17-544.2North 2968.0Latitude 26 ° 49 ' 45 "NLongitude 80 ° 33 ' 00 "WAPPLICANT NAME AND TITLE: Gus Cepero, Vice-PresidentAPPLICANT ADDRESS: P.O. Box 86, South Bay, FL 33493

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Sol-Energy, Inc.

I certify that the statements made in this application for a construction permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Gus CeperoGus Cepero, Vice-President

Name and Title (Please Type)

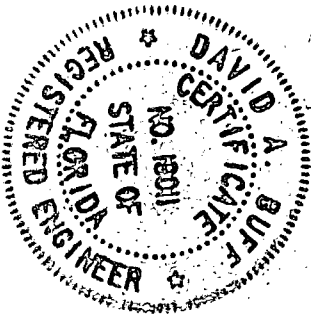
Date: 9/25/92 Telephone No. (407) 996-9072

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been designed/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

¹See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.



Signed

David A. Buff

David A. Buff

Name (Please Type)

KBN Engineering and Applied Sciences, Inc.

Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605

Mailing Address (Please Type)

Florida Registration No. 19011 Date: 9/29/92 Telephone No. (904) 331-9000

SECTION II: GENERAL PROJECT INFORMATION

- A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Refer to PSD report

- B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction May 1993 Completion of Construction December 1995

- C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Selective non-catalytic reduction systems: \$3.0 million

Electrostatic precipitators: \$4.2 million

Mercury control systems: \$0.5 million

- D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Not applicable

E. Requested permitted equipment operating time: hrs/day 24; days/wk 7; wks/yr 52;
If power plant, hrs/yr 8,760; if seasonal, describe: _____

F. If this is a new source or major modification, answer the following questions.
(Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? Yes
 - a. If yes, has "offset" been applied? No
 - b. If yes, has "Lowest Achievable Emission Rate" been applied? No
 - c. If yes, list non-attainment pollutants. Ozone
2. Does best available control technology (BACT) apply to this source?
If yes, see Section VI. Yes
3. Does the State "Prevention of Significant Deterioration" (PSD)
requirement apply to this source? If yes, see Sections VI and VII. Yes
4. Do "Standards of Performance for New Stationary Sources" (NSPS)
apply to this source? Yes
5. Do "National Emission Standards for Hazardous Air Pollutants"
(NESHAP) apply to this source? No

- H. Do "Reasonably Available Control Technology" (RACT) requirements apply
to this source? No
- a. If yes, for what pollutants? _____
 - b. If yes, in addition to the information required in this form, any information
requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any
justification for any answer of "No" that might be considered questionable.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
	<i>Not applicable</i>			

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): *Not applicable*

2. Product Weight (lbs/hr): *Not applicable*

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

Name of Contaminant	Emission ¹		Allowed ² Emission Rate per Rule 17-2	Allowable ³ Emission lbs/hr	Potential ⁴ Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
	<i>See Section 2.0 of</i>						
	<i>PSD report</i>						

¹See Section V, Item 2.

²Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

³Calculated from operating rate and applicable standard.

⁴Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
<i>Electrostatic Precip.</i>	<i>PM</i>	<i>>98%</i>	<i>Submicron</i>	<i>manufacturer</i>
<i>Mercury Control System</i>	<i>Hg</i>	<i>0-30%</i>	<i>N/A</i>	<i>manufacturer</i>
<i>NO_x Control System</i>	<i>NO_x</i>	<i>approx 40%</i>	<i>N/A</i>	<i>manufacturer</i>

E. Fuels (per boiler)

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
<i>Biomass</i>		<i>156,471 lb/hr</i>	<i>665</i>
<i>No. 2 Oil</i>		<i>3,333 gal/hr</i>	<i>460</i>
<i>Coal</i>		<i>38,333 lb/hr</i>	<i>460</i>

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur: Refer to Section 2.0 of PSD report Percent Ash: _____

Density: _____ lbs/gal Typical Percent Nitrogen: _____

Heat Capacity: _____ BTU/lb _____ BTU/gal

Other Fuel Contaminants (which may cause air pollution): _____

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average N/A Maximum _____

G. Indicate liquid or solid wastes generated and method of disposal.

Wastewater, which is primarily cooling water, will either be sent to a percolation pond, reused, or sent to wastewater treatment plant and then to percolation pond.

Ash will be disposed by landspreading or disposed offsite in an approved landfill.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 180 ft. Stack Diameter: 7.0 ft.
 Gas Flow Rate: _____ ACFM see PSD report DSCFM Gas Exit Temperature: see PSD report °F.
 Water Vapor Content: _____ % Velocity: _____ FPS

SECTION IV: INCINERATOR INFORMATION

Not applicable

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste _____
 Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____
 Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____
 Manufacturer _____
 Date Constructed _____ Model No. _____

	Volume (ft) ³	Heat Release (BTU/hr)	Fuel	Temperature (°F)
			Type BTU/hr	
Primary Chamber				
Secondary Chamber				

Stack Height: _____ ft. Stack Diameter: _____ Stack Temp. _____
 Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: ☐ Cyclone ☐ Wet Scrubber ☐ Afterburner
☐ Other (specify) _____

Brief description of operating characteristics of control devices: _____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
Not applicable.
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
See Section 2.0 of PSD report.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
See Section 2.0 of PSD report.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
See Section 2.0 of PSD report.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
See Section 2.0 of PSD report.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
See Section 2.0 of PSD report.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
See Section 2.0 of PSD report.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
See Section 2.0 of PSD report.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

See PSD report

- A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

☐ Yes ☐ No

Contaminant

Rate or Concentration

- B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

☐ Yes ☐ No

Contaminant

Rate or Concentration

- C. What emission levels do you propose as best available control technology?

Contaminant

Rate or Concentration

- D. Describe the existing control and treatment technology (if any).

1. Control Device/System:

2. Operating Principles:

3. Efficiency:*

4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:¹

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:²

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:¹

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:²

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

¹Explain method of determining efficiency.

²Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:¹

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:²

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:¹

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:²

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:¹

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:²

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

¹Explain method of determining efficiency.

²Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:¹

Contaminant

Rate or Concentration

(8) Process Rate:¹

b. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:¹

Contaminant

Rate or Concentration

(8) Process Rate:¹

10. Reason for selection and description of systems:

¹Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See PSD report

A. Company Monitored Data

1. _____ no. sites _____ TSP _____ () SO²* _____ Wind spd/dir

Period of Monitoring _____ / _____ / _____ to _____ / _____ / _____
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

- a. Was instrumentation EPA referenced or its equivalent? ☐ Yes ☐ No
- b. Was instrumentation calibrated in accordance with Department procedures?
☐ Yes ☐ No ☐ Unknown

B. Meteorological Data Used for Air Quality Modeling

1. _____ Year(s) of data from _____ / _____ / _____ to _____ / _____ / _____
month day year month day year
2. Surface data obtained from (location) _____
3. Upper air (mixing height) data obtained from (location) _____
4. Stability wind rose (STAR) data obtained from (location) _____

C. Computer Models Used

1. _____ Modified? If yes, attach description.
2. _____ Modified? If yes, attach description.
3. _____ Modified? If yes, attach description.
4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data

Pollutant	Emission Rate
TSP	_____ grams/sec
SO ²	_____ grams/sec

E. Emission Data Used in Modeling

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review.

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources.

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.

APPENDIX E

**SOURCE CONTRIBUTION TO MAXIMUM
24-HOUR AND 3-HOUR AAQS AND PSD IMPACTS**

Table E-1. Source Contributions to Key ISCST2 Short-term AAQS and PSD Maximum Impacts

AAQS: 24-HourTotal Modeled Concentration: 206.4 $\mu\text{g}/\text{m}^3$, at (270°, 6,600m), End Date 84121524.

U.S. Sugar Corp.--Bryant -	185.7
Proposed Sol-Energy -	19.5
FPL - Riviera Beach	1.1
West Palm Beach RRF -	0.1

AAQS: 3-HourTotal Modeled Concentration: 1,055.3 $\mu\text{g}/\text{m}^3$, at (272°, 6,200m), End Date 82070515.

Proposed Sol-Energy -	26.9	$\mu\text{g}/\text{m}^3$
FPL - Riviera Beach -	7.1	
US Sugar Corp-Bryant -	1,020.8	
Palm Beach County RRF -	0.5	

PSD Class II: 24-HourTotal Modeled Concentration: 76.0 $\mu\text{g}/\text{m}^3$ at (232°, 1,600 m), End Date 85100824

Proposed Sol-Energy	76.0	$\mu\text{g}/\text{m}^3$
---------------------	------	--------------------------

PSD Class II: 3-HourTotal Modeled Concentration: 215.5 $\mu\text{g}/\text{m}^3$, at (182°, 1,200m), End Date 84090812.

Proposed Sol-Energy -	208.3	$\mu\text{g}/\text{m}^3$
FPL Martin -	5.8	
Bechtel Indiantown -	1.4	

PSD Class I: 24-Hour

End Date:	83101624		83081724		83060524	
Receptor	(544000,2848600)		(550300,2839000)		(546000,2848600)	
Source Contributions	ISCST2	MESOPUFFII	ISCST2	MESOPUFFII	ISCST2	MESOPUFFII
Proposed Flo-Energy -	0.00	0.00	0.04	0.04	0.00	0.00
Proposed Sol-Energy -	1.83	0.00	1.33	0.12	1.97	0.00
Dade Co. RRF -	1.17	1.17	0.53	0.53	0.00	0.00
Tarmac -	2.82	2.82	1.95	1.95	0.00	0.00
FPL Lauderdale -	-0.57	-0.57	-0.75	-0.75	0.00	0.00
S. Broward Co. RRF -	0.14	0.14	0.22	0.22	0.00	0.00
N. Broward Co. RRF -	0.00	0.00	0.45	0.45	0.00	0.00
Bechtel Indiantown -	0.12	0.12	0.10	0.10	0.16	0.16
FPL Martin -	2.18	2.18	1.54	1.54	2.86	2.85
Total	5.65	3.82	5.42	4.21	4.99	3.01

PSD Class I: 3-HourTotal Modeled Concentration: 22.8 $\mu\text{g}/\text{m}^3$, at (497000,2830500), End Date 82071621).

Proposed Flo-Energy	7.3	$\mu\text{g}/\text{m}^3$
Proposed Sol-Energy	1.3	
Bechtel Indiantown	1.1	
FPL-Martin	13.1	

APPENDIX F
SUPPLEMENTAL PSD CLASS I AREA ANALYSIS

SUPPLEMENTAL PSD CLASS I AREA ANALYSIS

INTRODUCTION

A long-range transport modeling analysis was performed in order to refine SO₂ impacts in the Everglades National Park (ENP) PSD Class I area. The long-range transport model MESOPUFF II was used to address impacts from the proposed Sol-Energy cogeneration facility.

The protocol for this analysis is derived from a previous MESOPUFF II modeling protocol submitted to FDER, EPA Region IV, and the National Park Service on behalf of Florida Power Corporation in March, 1992 (FPC, 1992a). A final approval for that protocol was granted in June, 1992 (U.S. Department of Interior, 1992b). No technical changes to that protocol have been made. The computational grid domain has been changed to cover all of south Florida and the ENP. The meteorological data set has been redesigned to be most representative of transport conditions in south Florida.

As discussed in Section 6.0, ambient air quality analyses have been performed to demonstrate compliance of the proposed project with AAQS and PSD Class II and I increments. The model selection and application for those analyses were based on recommendations in the U.S. Environmental Protection Agency (EPA) "Guideline on Air Quality Models (Revised)", 1990. The air dispersion model used in these analyses was the ISCST2 model, which is intended to predict impacts up to 50 kilometers (km) from a source. This model is referenced in Appendix A ("Appendix A" model) of the modeling guidelines, which means that the model may be used without justifying the use of technical methods and procedures provided the recommended regulatory options are selected. Because the proposed Sol-Energy cogeneration facility is more than 100 km from the Class I area, the ISCST2 model is not appropriate for refining model impacts in the Class I area.

The modeling guideline does not specify a preferred model or protocol for long-range transport beyond 50 km. However, the above mentioned regulatory agencies have recommended the use of a long-range transport model, such as the MESOPUFF II model, to address impacts for such an application. Although the MESOPUFF II model is not an "Appendix A" model from the EPA modeling guidelines, it is referenced in Appendix B ("Appendix B" model) of the modeling guidelines and can be used on a case-by-case basis provided it can perform critical calculations or routines that are not available from an "Appendix A" model. In this case, the ISCST2 model, an

"Appendix A" model, does not have the necessary dispersion and transport routines to adequately address long-range transport of plumes from emission sources. Since the proposed facility is more than 50 km from the critical receptors, the MESOPUFF II model is an appropriate method for addressing impacts at the ENP. The modeling methods and assumptions used in the MESOPUFF II model are presented in the following sections.

GENERAL DESCRIPTION OF MESOPUFF II MODEL

MESOPUFF II is a long-range transport model that is currently recommended by EPA for determining source impacts at distances greater than 50 km. Based on discussions with FDER, EPA and NPS, this model can be used for the PSD Class I increment consumption analysis in support of air permit applications for emission sources located more than 50 km from a Class I area. The MESOPUFF II model has two preprocessor programs, READ56 and MESOPAC II, and one postprocessor program, MESOFIL II. The READ56 program is a preprocessor program to MESOPAC II, which is designed to read upper air (i.e., sounding) data obtained from the National Climatic Data Center (NCDC) in Asheville, North Carolina, and to reformat the data for use in the MESOPAC II program. The READ56 program also identifies missing data records. Missing data identified by READ56 must be filled in manually before input to the MESOPAC II program.

The MESOPAC II program is the meteorological preprocessor program for MESOPUFF II. The MESOPAC II program reads the upper air data file output from the READ56 program, as well as hourly surface meteorological data and hourly precipitation data collected at stations within the modeling area. Other data required for the MESOPUFF II model include land use and surface roughness lengths for each receptor grid point to be modeled.

The MESOPUFF II model provides concentration results for user-specified averaging times. The results can be processed by the MESOFIL II program to obtain additional statistical information about the concentrations produced from MESOPUFF II (e.g., annual average values).

Postprocessor programs are used to produce highest, second-highest (HSH) short-term concentrations from MESOPUFF II model's output. The annual average and HSH concentrations for the 3- and 24-hour averaging period can be compared directly to allowable PSD Class I increments.

METEOROLOGICAL DATA

The general grid in which the meteorological data was prepared and processed consisted of a model domain that covered an area of 90,000 km², extending 300 km in the east-west and north-south directions. There are a total of 196 cells within the grid, with each cell covering a 400-km² area or 20 km in the east-west and north-south directions. The southwest corner of the model domain is located at UTM coordinates of 350,000 m, East, and 2,780,000 m, North in UTM Zone 17. The Class I area and emission sources are located within the grid and generally are 100 km or more from the grid's edges. The source, receptor and meteorological station locations within the MESOPUFF II coordinate system are presented in Table F-1.

The upper air data used in the analysis was read by the READ56 program to identify missing soundings and missing data for specific levels within a sounding. The program was modified to account for the data format changes that have occurred since the program originally was developed. The options selected for this program are presented in Table F-2.

Meteorological data for 1983 from the National Weather Service (NWS) stations located within or near the grid were used in the analysis. This year corresponds to the same year during which air dispersion modeling with the ISCST model indicated a 24-hour concentration in excess of 5.0 $\mu\text{g}/\text{m}^3$ in the Class I area. Upper air rawinsonde data for 1983 from the following upper air NWS stations were used:

1. Ruskin
2. West Palm Beach

These stations were selected because they are the nearest upper air stations to the study area. The data were reduced into 1-year records suitable for input to the READ56 program. Each station-year was run with the READ56 model to determine any missing data. The missing data was filled in by assuming data persistence from the previous valid observation (e.g., if data for the 12Z sounding are missing, the 00Z sounding from the previous day was used) or persistence from a lower level. Because the program expects data from the mandatory levels of 850, 700, and 500 millibars (mb), data were inserted at these levels by persisting wind data from a lower level or temperature data for the same level from the previous sounding.

Table F-1. MESOPUFF Model Source, Class I Receptor, and Meteorological Station Computational Grid Coordinates (Page 1 of 2)

	UTM-East	UTM-North	Computational Grid	
			X	Y
Sources:				
Sol-Energy Cogen	544.2	2968.0	10.71	11.40
Flo-Energy Cogen	525.0	2939.4	9.75	9.97
Dade Co Resource Recov.	564.3	2857.4	11.72	5.87
Tarmac	562.9	2861.7	11.65	6.08
FPL Lauderdale	580.1	2883.3	12.51	7.17
S. Broward Co RRF	579.6	2883.3	12.48	7.17
N. Broward Co RRF	583.6	2907.6	12.68	8.38
Lee County RRF	424.0	2946.0	4.70	10.30
Southern Gardens	487.6	2957.6	7.88	10.88
Bectel Indiantown	545.6	2991.5	10.78	12.58
FPL Martin	543.1	2992.9	10.66	12.64
Class I Receptors:				
1	557.0	2789.0	11.35	2.45
2	556.6	2792.0	11.33	2.60
3	556.0	2796.0	11.30	2.80
4	553.0	2796.5	11.15	2.83
5	548.0	2796.5	10.90	2.83
6	542.7	2796.5	10.64	2.83
7	542.7	2800.0	10.64	3.00
8	542.7	2805.0	10.64	3.25
9	542.7	2810.0	10.64	3.50
10	542.0	2811.0	10.60	3.55
11	541.3	2814.0	10.57	3.70
12	542.7	2816.0	10.64	3.80
13	544.1	2820.0	10.71	4.00
14	543.5	2824.6	10.68	4.23
15	545.0	2829.0	10.75	4.45
16	545.7	2832.2	10.79	4.61
17	546.2	2835.7	10.81	4.78
18	548.6	2837.5	10.93	4.88
19	550.3	2839.0	11.02	4.95
20	445.0	2839.0	5.75	4.95
21	440.0	2839.0	5.50	4.95
22	550.5	2844.0	11.03	5.20
23	545.0	2844.0	10.75	5.20
24	540.0	2844.0	10.50	5.20
25	550.3	2848.6	11.02	5.43
26	545.0	2848.6	10.75	5.43
27	540.0	2848.6	10.50	5.43
28	535.0	2848.6	10.25	5.43
29	530.0	2848.6	10.00	5.43
30	525.0	2848.6	9.75	5.43
31	520.0	2848.6	9.50	5.43

Table F-1. MESOPUFF Model Source, Class I Receptor, and Meteorological Station Computational Grid Coordinates (Page 2 of 2)

	UTM-East	UTM-North	Computational Grid	
			X	Y
32	515.0	2848.6	9.25	5.43
33	515.0	2843.0	9.25	5.15
34	515.0	2838.0	9.25	4.90
35	515.0	2833.0	9.25	4.65
36	510.0	2833.0	9.00	4.65
37	505.0	2833.0	8.75	4.65
38	500.0	2833.0	8.50	4.65
39	495.0	2833.0	8.25	4.65
40	494.5	2837.0	8.23	4.85
41	491.5	2841.0	8.08	5.05
42	488.5	2845.5	7.93	5.28
43	483.0	2848.5	7.65	5.43
44	480.0	2852.5	7.50	5.63
45	475.0	2854.0	7.25	5.70
46	473.5	2857.0	7.18	5.85
47	473.5	2860.0	7.18	6.00
48	469.0	2860.0	6.95	6.00
49	464.0	2860.0	6.70	6.00
50	459.5	2864.0	6.48	6.20
51	454.0	2864.0	6.20	6.20
Meteorological Station:				
West Palm Beach	587.9	2951.5	12.895	10.573
Miami	573.5	2853.5	12.177	5.677
Fort Myers	413.7	2940.4	4.185	10.019
Ruskin	361.9	3064.5	1.597	16.227

Table F-2. Options Selected for READ56 Program- Proposed Sol-Energy Cogeneration

Variable	Description	Selected Value
1. CARD 1 - STARTING AND ENDING HOURS, UPPER PRESSURE LEVEL		
IBYR, IBDAY, IBHR, IEYR, IEDAY, IEHR	Starting and ending year, day, hour	As needed
PSTOP	Top pressure level for which data are extracted	500 mb
2. CARD 2 - MISSING DATA CONTROL VARIABLES		
LHT	Height field control variable	True ^a
LTEMP	Height field control variable	True ^a
LWD	Wind direction field control variable	True ^a
LWS	Wind speed field control variable	True ^a

^a Program run a second time with value set to false in order provide a missing value indicator for mandatory levels of 850, 700, and 500 mb. Data for these levels are input by user.

The MESOPAC II program was run to process the surface and upper air meteorological data for a format acceptable to the MESOPUFF II model. The options selected for this program are presented in Table F-3. The program was modified to account for the data format changes that have occurred since the program originally was developed. The surface meteorological data were obtained for the 5-year period of 1982 to 1986 from the following NWS stations, all located within the grid:

1. West Palm Beach
2. Miami and
3. Fort Myers

Hourly precipitation data were not utilized for any of the above surface meteorological stations. Land use data were developed for this grid from existing data developed by Argonne National Laboratory ("A Guide for Estimating Dry Deposition Velocities of Sulfur over the Eastern United States and Surrounding Regions, C.M. Sheih, et al., 1979). Since the model allows only a single land use type to be specified for each grid square, the land use category covering the greatest fraction of the total area within each grid square was selected.

MESOPUFF II MODELING APPROACH

The MESOPUFF II model was used to predict ambient concentrations at the same PSD Class I receptor location at which the ISCST2 predicted a refined 24-hour average concentration at or in excess of $5.0 \mu\text{g}/\text{m}^3$. The model was run for the same meteorological periods identified by the ISCST2 model as causing the high concentrations (see Section 6.9.4). The options selected for the MESOPUFF II model are presented in Table F-4. Based on recommendations by the National Park Service and EPA, the distance to which the Turner dispersion parameters apply was 50 km (the model default distance is 100 km). After that distance, the dispersion parameters are based on time-dependent equations.

Emissions and stack parameters for the proposed Sol-Energy cogeneration facility only were processed into the MESOPUFF II model input format. Concentrations were predicted at the same discrete receptors along the boundary of the ENP at which the high concentrations were obtained. Predicted highest 24-hour SO_2 concentrations were obtained for at least three days prior and two days after the predicted days of the modeled high 24-hour concentrations.

Table F-3. Options Selected for MESOPAC II Program- Proposed Sol-Energy Cogeneration Facility
(Page 1 of 2)

Variable	Description	Selected Value
1. CARD GROUP 1 - TITLE		
TITLE	Title of run	As needed
2. CARD GROUP 2 - GENERAL RUN INFORMATION		
NYR, IDYSTR, IHRMAX	Year, start day, and number	As needed
NSSTA, NUSTA	Number of surface and rawinsonde stations	As needed
3. CARD GROUP 3 - GRID DATA		
IMAX, JMAX	Number of grid points in the X and Y directions	15, 15
DGRID	Grid spacing	20 km
4. CARD GROUP 4 - OUTPUT OPTIONS		
Various	Disk and printer control variables for writing data to disk	As needed
5. CARD GROUP 5 - LAND USE CATEGORIES AT EACH GRID POINT		
ILANDU	Land use categories at each grid point	15 by 15 array
6. CARD GROUP 6 - DEFAULT OVERRIDE OPTIONS		
IOPTS(1)	Surface wind speed measurement heights control variable	0 (Default- 10 m)
IOPTS(2)	von Karman constant control variable	0 (Default)
IOPTS(3)	Friction velocity constants control variable	0 (Default)
IOPTS(4)	Mixing height constants control variable	0 (Default)
IOPTS(5)	Wind speed control variable	0 (Default - RADIUS = 99 km, ILWF = 2, IUWF = 4)

Table F-3. Options Selected for MESOPAC II Program- Proposed Sol-Energy Cogeneration Facility
(Page 2 of 2)

Variable	Description	Selected Value
IOPTS(6)	Surface roughness lengths control variable	0 (Default)
IOPTS(7)	Option to adjust heat flux estimate	0 (Default)
IOPTS(8)	Radiation reduction factors control variable	0 (Default)
IOPTS(9) variable	Heat flux constant control	0 (Default)
IOPTS(10)	Option to begin run at date other than at start of meteorological data files	0 or 1, as needed
7.- 14. CARD GROUPS 7 TO 14		
Various	Options input to override default values	Not used
15. CARD GROUP 15 - SURFACE STATION DATA		
Various	Surface meteorological station information	As needed
16. CARD GROUP 16 - RAWINSONDE STATION DATA		
Various	Rawinsonde meteorological station information	As needed

Note: Precipitation data were available and were used in the enhanced operation mode of the MESOPUFF II modeling.

Table F-4. Options Selected for MESOPUFF II Program- Proposed Sol-Energy Cogeneration Facility
(Page 1 of 3)

Variable	Description	Selected Value
1. CARD GROUP 1 - TITLE		
TITLE	Title of run	As needed
2. CARD GROUP 2 - GENERAL RUN INFORMATION		
NSYR, NSDAY, NSHR	Year, start day and hour	As needed
NADVTS	Number of hours in run	As needed
NPTS	Number of point sources	As needed
NAREAS	Number of area sources	Not used
NREC	Number of non-gridded receptors	13 (Class I area)
NSPEC	Number of chemical species to model	1 (SO ₂)
3. CARD GROUP 3 - COMPUTATIONAL VARIABLES		
IAVG	Concentration averaging time	24 hours
NPUF	Puff release rate for each source	1 puff/hour
NSAMAD	Minimum sampling rate	2 samples/hour
LVSAMP	Variable sampling rate option	True (increase rate with higher wind speeds)
WSAMP	Reference wind speed used in variable sampling rate option (used if LVSAMP is true)	2 m/s
LSGRID	Control variable for concentration computations at sampling grid points	False (sampling at non-gridded points only)
AGEMIN	Minimum age of puffs to be sampled	900 seconds (should not be larger than 3600 seconds)

Table F-4. Options Selected for MESOPUFF II Program- Proposed Sol-Energy Cogeneration Facility
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Variable	Description	Selected Value
4. CARD GROUP 4 - GRID INFORMATION		
Various	Numbers that define the beginning and end of the meteorological and computational grids	1,15
MESHDN	Sampling grid spacing factor	1
5. CARD GROUP 5 - TECHNICAL OPTIONS		
LGAUSS	Vertical concentration distribution option	True
LCHEM	Chemical transformation option	False ^a
LDRY	Dry deposition option	False ^a
LWET	Wet deposition option	False ^a
L3VL	Three vertical layer option	False ^a
6. CARD GROUP 6 - DEFAULT OVERRIDE OPTIONS		
Various	Disk and printer option to write data to disk	As needed
LPRINT	Printer output option (Print every IPRINT hours)	True
IPRINT	Printing interval	24 hours
7. CARD GROUP 7 - DEFAULT OVERRIDE OPTIONS		
IOPTS(1)	Control variable for input of dispersion parameters	1 (see Card Group 8)
IOPTS(2)	Control variable for input of diffusivity constants	0 (Default)
IOPTS(3)	Control variable for input of SO ₂ canopy resistance	0 (Default)
IOPTS(4)	Control variable for input of dry deposition parameters	0 (Default)

Table F-4. Options Selected for MESOPUFF II Program- Proposed Sol-Energy Cogeneration Facility
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Variable	Description	Selected Value
IOPTS(5)	Control variable for input of wet removal parameters	0 (Default)
IOPTS(6)	Control variable for input of chemical transformation method	0 (Default)
8. CARD GROUP 8 - DISPERSION PARAMETERS		
AY, BY, AZ, BZ, AZT	Arrays of dispersion coefficients	Default
TMDEP	Distance beyond which the time-dependent equations are used for sigma y and z	50,000 m (Default is 100,000 m)
JSUP	Stability class used to determine growth rates for puffs above boundary layer	5 (Default)
9.- 13. CARD GROUPS 9 TO 13		
Various	Options input to override default values	Not used
14. CARD GROUP 14 - POINT SOURCE DATA		
Various	Point source information- location, stack and emission data	As needed
15. CARD GROUP 15 - AREA SOURCE DATA		
Various	Area source information- location, initial dispersion and emission data	Not used
16. CARD GROUP 16 - NON-GRIDDED RECEPTOR COORDINATES		
XREC, YREC	X- and Y-coordinates of non-gridded receptors	Used

^a This option was not used when the MESOPUFF II model was run in the inert mode. In the enhanced mode, this option was considered.

Level 1

The predicted 24-hour concentrations from MESOPUFF for the proposed cogeneration facility were substituted into the ISCST2 model result and added to the predicted impacts produced for all other sources with the ISCST2 model. If the proposed source's impacts using MESOPUFF II model were less than the significant impact levels or the total predicted concentrations were less than the Class I increment, no additional modeling was required.

Level 2

If violations were predicted after the initial analysis, MESOPUFF II modeling was performed which involved using the results from Level 1 and performing additional modeling with the MESOPUFF II model for those sources located more than 50 km from the Class I area. These predicted concentrations were substituted for the ISCST2 model results. These MESOPUFF II model concentrations were added to those produced with the ISCST2 model for sources located at or within 50 km of the Class I area and MESOPUFF II model results from the proposed source to determine the total PSD Class I increment consumption. If the total predicted concentrations were less than the Class I increment, no additional modeling was required.

Level 3

These model runs incorporated the use of chemical transformation processes, wet and dry deposition, and vertical concentration distributions and is referred to as the enhanced mode of model operation.

MESOPUFF II MODEL RESULTS

A Level 1 modeling analysis was initially performed. A summary of the highest 24-hour SO₂ concentrations in the PSD Class I area predicted for 1983 using the ISCST2 model, and for which the proposed source's impact was greater than the significant impact level, are presented in Table F-5. The summary also contains the predicted concentration from Level 1 of the MESOPUFF II modeling. As shown, the results from Level 1 reduced the contribution from the proposed cogeneration facility from the 1.33 to 1.97 $\mu\text{g}/\text{m}^3$ range predicted with the ISCST2 model to the 0 to 0.12 $\mu\text{g}/\text{m}^3$ range predicted with MESOPUFF II. The 0.12 $\mu\text{g}/\text{m}^3$ concentration was the maximum predicted for the days processed. Based on these results, the ISCST2 model's predicted values of 5.42 and 5.65 $\mu\text{g}/\text{m}^3$ reduce to 4.21 and 3.82 $\mu\text{g}/\text{m}^3$, respectively, which are in compliance with the 24-hour PSD Class I increment of 5.0 $\mu\text{g}/\text{m}^3$. Further Level 2 or 3 modeling analyses were therefore not performed for these periods.

Table F-5. Summary of 1983 Predicted High 24-Hour SO₂ Concentration in the Class I Area Using the ISCST2 and MESOPUFF II Models

<u>Time Period</u>		<u>Receptor</u> <u>Receptor</u> <u>Number</u>	<u>ISCST2 Concentrations</u> <u>($\mu\text{g}/\text{m}^3$)</u>		<u>MESOPUFF II Level 1</u> <u>Concentration ($\mu\text{g}/\text{m}^3$)</u>		
<u>Hour</u> <u>Ending</u>	<u>Calendar</u> <u>Date</u> <u>Month/Day</u>		<u>All</u> <u>Sources</u>	<u>Proposed</u> <u>Sol-Energy</u> <u>Facility</u>	<u>Proposed</u> <u>Sol-Energy</u> <u>Facility</u>	<u>Adjusted</u> <u>Total</u>	<u>Is</u> <u>Increment</u> <u>Exceeded?</u>
24	8/17	19	5.42	1.33	0.12	4.21	No
24	10/16	26	5.65	1.83	0.00	3.82	No
24	6/5	26	4.99	1.97	0.00	3.02	No

APPENDIX G

U.S. SUGAR BRYANT SO₂ EMISSIONS

Table G-1. U.S. Sugar Bryant Mill Worst-Case SO₂ Emissions

Boiler	Maximum Heat Input (MM Btu/hr)	SO ₂ Emissions							
		Fuel Oil		Bagasse		Oil	Bagasse ^b	Total	
		gal/hr	MM Btu/hr	MM Btu/hr	lb/hr(dry)	(lb/hr)	(lb/hr)	(lb/hr)	(g/s)
<u>WORST-CASE 3-HOUR</u>									
1	385.0 ^a	1,260	189.1	195.9	24,491	449.1	12.2	461.3	58.12
2	385.0 ^a	1,260	189.1	195.9	24,491	449.1	12.2	461.3	58.12
3	385.0 ^a	1,260	189.1	195.9	24,491	449.1	12.2	461.3	58.12
5	671.0	1,436	215.5	455.5	56,939	511.8	28.5	540.2	68.07
Totals	1,826.0	5,216	782.7	1,043.3	130,411	1,858.9	65.2	1,924.1	242.4
<u>WORST-CASE 24-HOUR</u>									
1	385.0 ^a	416	64.0	321.0	40,125	148.3	20.1	168.3	21.21
2	385.0 ^a	416	62.4	322.6	40,322	148.3	20.2	168.4	21.22
3	385.0 ^a	416	62.4	322.6	40,322	148.3	20.2	168.4	21.22
5	583.0	1,436	215.5	367.5	45,939	511.8	23.0	534.7	67.38
Totals	1,738.0	2,684	404.3	1,333.7	166,708	956.6	83.4	1,039.9	131.0

^a 24-hour average.^b Assumes 50% SO₂ removal when burning bagasse.

Notes:

Bagasse - 8,000 Btu/lb

0.05% sulfur average (dry basis)

No. 6 Fuel Oil - AP-42 factor - 157S lb/1000 gal

2.27% sulfur, based on average sulfur content in 1991:

Blr 1	36,359 gal	2.5 %S
Blr 2	37,369 gal	2.5 %S
Blr 3	34,903 gal	2.5 %S
Blr 5	15,836 gal	0.7 %S

Avg. = 124,467 gal 2.27 %S