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Section 1

Introduction and Overview

The Hillsborough County Waste Energy Recovery Facility (Facility) is proposing to construct and operate a new 600-ton-per-day (tpd) boiler, which would be the Facility's new Unit 4. The Facility currently has three mass-burn combustion units with nominal nameplate capacities of 400 tpd each. The new Unit 4 would increase the solid waste processing capacity of the Facility from 1200 tpd to 1800 tpd. The proposed new Unit 4 would also increase the Facility's steam electrical generating capacity from 39 MW to 47 MW.

Hillsborough County (County) has prepared this Application to satisfy the requirements set forth in the Florida Electrical Power Plant Siting Act (PPSA), Sections 403.501-518, Florida Statutes, and the PPSA rules adopted by the Florida Department of Environmental Protection (FDEP) in Chapter 62-17, F.A.C. This Volume III contains the Air Permit application portions of the Application. With this Volume, the County seeks to modify the air emission provisions of its Power Plant Site Certification (PA 83-19), Prevention of Significant Deterioration (PSD) Air Permit (PSD-FL-121(B)), and Title V Air Operation Permit (No. 0570261-005-AV), for the addition of the new Unit 4. This Volume provides the information required by Chapter 62-212.400, F.A.C., for a PSD application. Section 2 describes the applicable air quality regulatory requirements for the new Unit 4. Section 3 contains the Best Available Control Technology Analyses Evaluation. Section 4 presents the air pollutant emission rate estimates for the new Unit 4. Section 5 describes ambient air quality conditions in the project area. Section 6 presents the dispersion modeling analyses, and Section 7 presents the Additional Impact Analyses (impacts to visibility, growth, and vegetation and soils) required by the Rule. **Appendix A** contains the emission factor calculations. **Appendix B** contains the supporting documentation for Best Available Control Technology. **Appendix C** contains all the relevant DEP forms for the PSD Application.

Best Available Control Technology for the proposed Unit 4 would consist of a spray dryer absorber (SDA), a fabric filter (FF), an activated carbon injection (ACI) system, and an enhanced selective non-catalytic reduction (SNCR) system. With this control technology, the modeling analyses show that:

- Unit 4 would consume less than 2% of the PSD Class II Increment, and the Facility as a whole (including Unit 4), less than 12% of the Increment.
- Unit 4 and the Facility as a whole would have maximum predicted concentrations well under the Florida and National Ambient Air Quality Standards. Unit 4's highest concentration would be less than 1% of any Standard; and the Facility as a whole (with background concentrations and Unit 4 added) would have concentrations less than 75% of any Standard.

- Unit 4's air emissions would have an insignificant effect on the nearest Class I (pristine) Area, the Chassahowitzka National Wildlife Refuge. The maximum predicted concentration would be less than 44% of the Class I Significant Impact Level (SIL), and consume less than 1% of the Class I PSD Increment.

- Unit 4 would have non-criteria air pollutant maximum predicted concentrations that would be about 80% or less of any guideline Ambient Reference Concentration.

- Unit 4 would have negligible effects on regional growth, visibility in Class I Areas, and vegetation and soils in the project area.

Section 2
Regulatory Review

2.1 Applicable Regulations

Air quality regulations promulgated by the United States Environmental Protection Agency (USEPA) and the Florida Department of Environmental Protection (FDEP) define ambient air quality standards and regulate the sources of air contaminants in order to achieve and maintain these ambient standards. The proposed expansion of the Hillsborough County Resource Recovery Facility has been evaluated to verify compliance with the following rules and regulations:

- Prevention of Significant Deterioration (PSD)
- Non-Attainment New Source Review (NSR)
- Ambient Air Quality Standards (AAQS)
- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Florida Administrative Code Requirements (F.A.C.)
- Federal Aviation Administration (FAA) regulations governing stack height
- Florida Electrical Power Plant Siting Act (PPSA)

The FDEP operates a PSD program that has been "approved" by the USEPA. In many cases, the FDEP's rules are the same as those of the USEPA. However, for those instances where the Florida rules are more restrictive than those of the USEPA, the Florida regulation has been applied.

2.2 PSD Provisions

The federal PSD air permit program was established in 1974 to prevent degradation of air quality in regions of the country that were currently in attainment with the AAQS. The PSD program requires that major sources in attainment areas obtain permits, and that emissions from these sources cannot cause degradation of ambient air quality beyond certain increments – and in no case, beyond the AAQS.

The PSD permit program is applicable to major sources of regulated air pollutants in attainment areas. Major sources are defined by their annual emission rate and the industrial category of the Facility. For example, a Facility is major if its emissions of any regulated pollutant exceed 100 tons per year and it is in one of 28 specified industrial source categories. The Facility is classified as major because it is a municipal incinerator capable of charging more than 50 tons per day of MSW and it has the potential to emit more than 100 tons per year of at least one regulated pollutant.

A physical modification to an existing PSD major source is subject to additional regulation if it results in a *significant* increase in emissions of any regulated pollutant. A *significant* emissions increase is an increase greater than or equal to the levels listed in **Table 2-1**.

Table 2-1
Thresholds for Major Modifications to PSD Major Sources

Pollutant	Emissions (tons/year)
Carbon monoxide Nitrogen oxides	100 40
Sulfur dioxide	40
Ozone (as VOCs)	40
Particulate matter	25
PM10	15
Total Reduced Sulfur (including H2S)	10
Sulfuric acid mist	7
Fluorides	3
Lead	0.6
Mercury	0.1
MWC organics	3.5 x 10-6
MWC metals	15
MWC acid gases	40

Source: 62-212.400, Table 212.400-2, F.A.C.

In general, a PSD permit application must contain the following components:

- A complete description of the nature and operation of the source
- A Best Available Control Technology (BACT) determination
- An analysis of existing ambient air quality

- An impact assessment demonstrating that emissions from the new source will not cause a violation of ambient air quality standards or PSD increments
- An assessment of the source's impact on air quality related values including soils, vegetation, visibility and general commercial, residential, and industrial growth.

If the proposed source or modification is within 100 km of a designated Class I area, concurrence with the Federal Land Manager (FLM) for the Class I area must also be established before a PSD permit can be issued, however EPA has the authority to overrule the FLM. Class I areas are those pristine areas of the United States, such as national parks and wilderness areas. The Chassahowitzka Wilderness Area is located less than 100 km from the Facility. Section 7 of this report addresses Additional Impact Analyses and contains the Class I impact analysis for the proposed modification.

2.2.1 Source Applicability

Construction of the fourth unit at the Facility constitutes a major modification to an existing major source because the Facility combusts more than 50 tons per day of municipal solid waste. Also, the new Unit 4 will exceed the PSD significance levels in Table 2-1 for at least one of the PSD regulated pollutants. PSD requirements apply to major modifications located in areas that have been designated as attainment or unclassifiable for the AAQS. As outlined in Section 5, the proposed project is located in an area that is classified as attainment or is unclassifiable for all criteria pollutants. For the purposes of source applicability, this project is defined as the addition of Unit 4 to the existing Facility. Units 1, 2, and 3 will not be modified by this project; therefore, Units 1, 2 and 3 are not subject to further PSD review at this time.

2.2.2 Pollutant Applicability

In accordance with Rule 62-212, F.A.C., a BACT analysis and air quality models are required for each PSD pollutant that is emitted at greater than the significance levels specified in Table 2-1. Estimates of anticipated emission rates have been developed. They are discussed in detail in Section 4. **Table 2-2** compares estimated emissions from Unit 4 with the PSD significance level. The maximum annual emission rates estimated in Table 2-2 are based on the assumption that the new unit would operate continuously, 24 hours per day, 365 days per year, at 110% of load. This is conservative because typical boiler availability rates for the industry are between 85 and 95 percent.

Table 2-2
PSD Pollutant Applicability for Unit 4

PSD Pollutant	PSD Significant Emission Rate[a] (tons/yr)	Proposed Unit 4 Emission Rate (tons/yr)	PSD Applicable
Carbon monoxide	100	113.4	Yes
Nitrogen oxides	40	256.1	Yes
Sulfur dioxide	40	84.3	Yes
Ozone (VOC)	40	12.0	No
Particulate Matter (Total)	25	25.1	Yes
PM_{10}	15	25.1	Yes
Total Reduced Sulfur (including H2S)	10	Negligible	No
Hydrogen Sulfide	10	Negligible	No
Sulfuric Acid Mist	7	74.4	Yes
Fluorides	3	3.5	Yes
Lead	0.6	0.243	No
Mercury	0.1	1.63×10^{-1}	Yes
Vinyl Chloride	1	Negligible	No
MWC Organics (Total Dioxins and Furans)[b]	3.5×10^{-6}	1.58×10^{-5}	Yes
MWC Metals (as PM)	15	25.1	Yes
MWC Acid Gases (as SO_2 and HCl)	40	195.4	Yes

Notes:

[a] Source: Rule 62-212.400, F.A.C. Table 212.400-2, and 40 CFR 52.21.

[b] Measured as total tetra- through octa- chlorinated dibenzo-p-dioxins and dibenzo furans.

2.3 Ambient Air Quality Standards

The current federal and state AAQS are enumerated in the baseline air quality discussion in Section 5. As discussed in Section 5, ambient air quality in the project's vicinity is currently better than the AAQS for all pollutants. The Facility Unit 4's compliance with AAQS after the proposed expansion is demonstrated in the air quality modeling analysis in Section 6.

The EPA promulgated new National Ambient Air Quality Standards (NAAQS) in July 1997 for PM less than 2.5 microns in diameter ($PM_{2.5}$) and a more stringent 8-hour-average ozone standard of 0.08 parts per million (ppm) to replace the current 1-hour-average standard of 0.12 ppm. The American Trucking Association challenged these new standards in court. On May 14, 1999, the United States Court of Appeals (D.C. Circuit) issued an opinion that the process for setting these standards was unconstitutional and that the standards were unenforceable. As a result, the new standards were held in abeyance. The EPA appealed this decision to the United States Supreme Court. On February 27, 2001, the United States Supreme Court overturned the D.C. Circuit Court ruling and found that:

- EPA has the right to establish health-based standards;
- EPA need not consider cost when setting standards; and
- EPA must revise its implementation policy for the new 8-hour ozone standard

The EPA designated attainment areas for the 8-hour ozone NAAQS and issued a Phase 1 implementation rule on June 15, 2004. (A rule containing reconsideration of some aspects of the implementation rule was promulgated on May 20, 2005.) The 1-hour ozone standard is being phased out and was replaced by the 8-hour standard on June 15, 2005. The EPA designated attainment areas for the $PM_{2.5}$ standard on December 17, 2004, but has not yet issued implementation rules for this standard. The EPA will retain both PM_{10} and $PM_{2.5}$ as NAAQS.

Because procedures for implementing the new $PM_{2.5}$ and 8-hour ozone NAAQS are still being developed by the EPA, this PSD Permit modification application does not contain a compliance demonstration for these two standards.

2.4 New Source Performance Standards

Applicability of the USEPA New Source Performance Standards (NSPS) in Title 40, Part 60 of the Code of Federal Regulations (40 CFR 60) to the Facility is summarized below. These federal NSPS are adopted in the state of Florida's regulations by reference in FAC 62-204.800(8)(b).

2.4.1 New Source Performance Standards for Large Municipal Solid Waste Combustors (Subpart Eb)

On August 27, 1997, USEPA promulgated the NSPS for large municipal waste combustors (MWC) newly constructed after September 20, 1994, or modified after June 19, 1996. The Subpart Eb NSPS were developed under Sections 111(d) and 129 of the CAA. Under Section 129 of the CAA, the NSPS were developed to reflect Maximum Achievable Control Technology (MACT) and to specify emission levels for additional pollutants. The NSPS set emission limits for MWC metals [particulate matter (PM), opacity, cadmium (Cd), lead (Pb), and mercury (Hg)], MWC acid gases [sulfur dioxide (SO_2), and hydrogen chloride (HCl)], MWC organics (dioxins/furans), nitrogen oxides (NO_X), and carbon monoxide (CO). The emission limits are based on the utilization of Good Combustion Practices (GCP) and Air Pollution Control (APC) systems consisting of Spray Dryer Absorber (SDA)/Fabric Filter (FF), Selective Non-Catalytic Reduction (SNCR), and Activated Carbon Injection (ACI) systems or SDA/electrostatic precipitator (ESP), SNCR, and ACI systems. The proposed Facility Unit 4 would include the use of GCP, SNCR, and SDA/FF/ACI systems designed to meet the NSPS, which are discussed below.

The NSPS apply to "large" MWC units, defined as any MWC unit capable of combusting more than 250 tons per day of municipal solid waste (40 CFR 60.50b(a)). Under 40 CFR 60.58b(j), MWC capacity for continuous feed combustors is calculated "based on 24 hours of operation at the maximum charging rate." For MWC units "that are designed based on heat capacity, the maximum charging rate shall be the maximum design charging rate." The maximum design charging rate is calculated "based on the maximum design heat input capacity," and a heating value of 10,500 kilojoules per kilogram or approximately 4,500 British thermal units per pound (Btu/lb) of MSW. The nominal design heat input capacity of the proposed Unit 4 is 250 MMBtu/hr, which is equivalent to approximately 660 tons per day of MSW at 4,500 Btu/lb. Therefore, the proposed Unit 4 is a "large" MWC unit, and subject to the emissions limitations in 40 CFR 60 Subpart Eb.

Florida adopted the Subpart Eb regulations by reference in FAC 62-204.800(8)(b)7. FDEP's mercury requirements in FAC 62-296.416 for MWCs have a more stringent numerical limit than the NSPS, but the NSPS have a more stringent mercury removal requirement. This is discussed in more detail in Section 2.9, below.

Table 2-3 summarizes the Subpart Eb limits, and compares them with the emissions limits proposed for Unit 4. In all cases, the emissions limits proposed for Unit 4 are the same as or lower than the emissions limits established by Subpart Eb.

Particulate Matter (PM) and MWC Metals

Subpart Eb requires large new MWC units to control PM to a level of 24 milligrams per dry standard cubic meter (mg/dscm) [0.010 grains/dry standard cubic foot (gr/dscf)] corrected to 7 percent O_2.

Table 2-3
40 CFR 60 Subpart Eb Air Pollutant Emissions Standards for Unit 4

Pollutant	**40 CFR 60 Subpart Eb Limit**[1,4]	**Unit 4 Proposed Emission Limit**[2,4]
Particulate Matter (PM)	24 mg/dscm (0.01 gr/dscf)	0.009 gr/dscf
PM_{10}	N/A	0.009 gr/dscf
Cadmium (Cd)	0.020 mg/dscm	0.020 mg/dscm
Lead (Pb)	0.20 mg/dscm	0.20 mg/dscm
Mercury (Hg)	80 ug/dscm or 85% Control[3]	70 ug/dscm or 85% Control[3]
Sulfur Dioxide (SO_2)	30 ppmdv or 80% Control[3] (24-hour geometric mean)	26 ppmdv or 80% Control[3] (24-hour geometric mean)
Sulfuric Acid Mist (SAM)	N/A	15 ppmdv
Hydrogen Chloride (HCl)	25 ppmdv or 95% Control[3]	25 ppmdv or 95% Control[3]
Hydrogen Fluoride (HF)	N/A	3.5 ppmdv
Nitrogen Oxides (NO_X)	180 ppmdv 1st year; 150 ppmdv thereafter (24-hour arithmetic mean)	110 ppmdv (24-hour arithmetic mean)
Municipal Waste Combustor Organics (Total PCDD/PCDF)	13.0 ng/dscm (avg. of three 4-hour test runs)	13.0 ng/dscm (avg. of three 4-hour test runs)
Carbon Monoxide (CO)	100 ppmdv (4-hour block arithmetic mean)	80 ppmdv (4-hour block arithmetic mean)
Ammonia (NH_3)	N/A	50 ppmdv

Notes:

[1] All limits shown are corrected to 7% oxygen.

[2] Basis for the proposed emissions limits is described in Section 3.

[3] Whichever is less restrictive.

[4] Compliance based on the average of three 1-hour tests, unless otherwise noted.

N/A = Not Applicable
ng = nanograms
ug = micrograms
mg = milligrams
dscm = dry standard cubic meter
dscf = dry standard cubic foot
gr = grain
lb = pound
ppmdv = parts per million by volume, dry basis

Compliance will be verified annually by compliance stack tests using USEPA Reference Method 5.

Subpart Eb also requires large MWC units to meet an opacity level of 10 percent using a six-minute block averaging time. Compliance must be verified both by annually using USEPA Reference Method 9 and by using continuous opacity monitors (COMs).

Subpart Eb also establishes specific emission levels for cadmium (Cd), lead (Pb), and mercury (Hg). Large MWC units are required to meet a Cd emission level of 0.020 mg/dscm (9 gr/million dscf) corrected to 7 percent O_2, a Pb emission level of 0.20 mg/dscm (81.6 gr/million dscf) corrected to 7 percent O_2, and an Hg emission level of 0.080 mg/dscm (35 gr/million dscf) or an 85 percent reduction in Hg emissions corrected to 7 percent O_2, whichever is less stringent. Compliance must be verified annually by compliance stack tests using USEPA Method 29.

MWC Acid Gases

The Subpart Eb NSPS for acid gases require large MWC units to control SO_2 emissions to a level of either 30 ppmv or 80 percent reduction (corrected to 7 percent O_2, dry basis, 24-hour geometric mean) and HCl emissions to a level of 25 ppmv or 95 percent reduction (corrected to 7 percent O_2, dry basis). Compliance with SO_2 emissions must be verified by using continuous emission monitors (CEMs), and compliance with HCl emissions will be verified annually by compliance stack tests using USEPA Method 26.

MWC Organics

Subpart Eb requires large new MWC units to meet a dioxin/furan emission level of 13 nanograms per dry standard cubic meter (ng/dscm) total mass corrected to 7 percent O_2. Compliance will be verified annually by compliance stack tests using USEPA Reference Method 23. Alternatively, compliance with a 7 ng/dscm corrected to 7 percent O_2 emission limit by all four units at the Facility for at least two years can qualify the Facility for dioxin/furan testing of only one unit (rather than all four) each year. Continuous control of MWC organic emissions is achieved by using Good Combustion Practices, which are described separately, below.

NO_X Emissions

Subpart Eb requires that large new MWC units control NOx emissions to a level of 180 ppmv [corrected to 7 percent O_2, dry basis, on a daily (24-hour) block arithmetic mean basis]. Compliance must be verified by using CEMs. After the first year of operation following the date on which the initial performance test is completed, NOx emissions cannot exceed 150 ppmv [corrected to 7 percent O_2, dry basis, on a daily (24-hour) block arithmetic mean basis]

Good Combustion Practices (GCP)

Subpart Eb requires large new MWC units to comply with specified operating practices that reflect GCP. These operating practices address CO levels, combustor load levels, and flue gas temperatures.

For a mass-burn refractory large new MWC unit, Subpart Eb specifies a CO emission limit of 100 ppmv (at 7 percent O_2, dry basis) on a four-hour block average basis. Compliance must be verified with Continuous Emission Monitors (CEMs).

MWC units are allowed to operate at up to 110 percent of the unit's maximum capacity, as achieved during the most recent successful dioxin/furan compliance test. Maximum capacity is determined based on the steam flow rate, which must be continuously monitored according to the ASME Power Test Code (PTC) for steam generating units (PTC4.1 and PTC19.5).

MWC units are required to establish a Facility-specific maximum flue gas temperature at the final PM control device inlet. The maximum demonstrated PM control device inlet temperature is the maximum four-hour block average temperature measured during the most recent successful dioxin/furan compliance test. The MWC must then be operated so that the temperature at the final PM control device inlet does not exceed this level by more than 17 deg. C (30 deg. F) on a four-hour block basis.

Operator Certification and Training

Subpart Eb requires full certification of all MWC shift supervisors and MWC chief Facility operators by the American Society of Mechanical Engineers (ASME) (certification QRO-1-1994) or an equivalent state certification program. The NSPS also require that at least one of the following persons be on duty at the MWC at all times when the MWC is combusting waste: a fully certified MWC chief Facility operator, a fully certified shift supervisor, or a provisionally certified chief Facility operator or shift supervisor. A provisionally certified control room operator is allowed to "stand-in" during times when a fully certified Facility chief operator and a fully certified shift supervisor are not on site.

In addition, Subpart Eb requires each owner or operator of an affected MWC unit to develop and maintain a site-specific operating manual and to review it with all employees associated with the operation of the MWC including MWC maintenance personnel, crane/load operators, and ash handlers. The manual and training must be updated annually. The Facility operator, Covanta Hillsborough, Inc. maintains this manual and will update it to include Unit 4 upon completion of acceptance testing.

Fly Ash or Bottom Ash Fugitive Emissions

Subpart Eb NSPS for fugitive ash emissions restrict visible emissions from ash conveyor systems, transfer points, buildings, or enclosures of ash conveying systems to 5 percent or less of the time during the observation period (for example, 9 minutes in a 3-hour observation period). Compliance will be verified annually by USEPA

Reference Method 22 observations. The visible emission limits do not apply during periods of maintenance or repair to ash conveying systems.

Siting and Materials Separation Plan Requirements

Subpart Eb requires that the owner/operator of the affected Facility prepare a materials separation plan for the Facility and its service area. The plan should discuss the amount of waste generation for the service area, the types and amounts of materials proposed for separation and recycling, and the methods proposed for separation. The owner/operator is required to make the plan available to the public; publish a notice for, and conduct, a public meeting; prepare a document responding to comments raised at the public meeting; and finalize the plan based on comments received. The owner/operator is required to submit to DEP, before submitting the PSD air permit application, a copy of the public notice for the meeting, a transcript of the meeting, the document summarizing comments and responses, and copies of both the draft and final materials separation plans. Volume II of this application includes the draft and final Materials Separation Plans along with the public notice and Public Hearing transcripts.

Subpart Eb also requires that the owner/operator prepare a siting analysis for the proposed MWC unit. The siting analysis is required to assess the impact of the proposed MWC unit on ambient air quality, visibility, soils, and vegetation. The analysis is also required to consider air pollution control alternatives that minimize, to the maximum extent practicable, potential risks to public health and the environment. The siting analysis is subject to the same public notice, public meeting, and response-to-comments requirements as the materials separation plan, and Subpart Eb allows their discussion at the same public meeting. However, the siting analysis is not required to be submitted to DEP until the initial notification of construction of the MWC unit is submitted. The information required for the siting analysis is contained in this PSD application and the related application under the Florida Electrical Power Plant Siting Act (see Volume II). The air quality evaluations and impacts analyses are contained in Chapters 6 and 7 of this PSD application. These analyses demonstrate compliance with the AAQS and PSD increments, which demonstrate that human health and the environment will be protected with an adequate margin of safety. The BACT determination in Section 3 evaluates air pollution control alternatives. Potential risks are also evaluated in the Health and Environmental Risk Assessment contained in Volume II.

Compliance and Testing

Subpart Eb includes testing and monitoring requirements for MWC metal emissions. These include PM, opacity, Cd, Pb, and Hg. It also requires testing and monitoring for MWC acid gas emissions (SO_2 and HCl), MWC organic emissions (dioxins/furans), MWC operating parameters (CO, load level, and flue gas temperature), and NOx. SO_2, NOx, and CO emissions must be determined using CEMs. Opacity must be monitored using a CEM and must be measured annually by USEPA Reference Method 9. Fugitive ash emissions must also be tested annually by

USEPA Reference Method 22. Emissions of other pollutants must be determined by annual stack tests.

The Subpart Eb emissions limits apply at all times, except during periods of MWC unit startup, shutdown, and malfunction. The NSPS limit the duration of each startup, shutdown or malfunction to no more than three hours per occurrence. However, if a malfunction is a loss of boiler water level control (for example, a boiler waterwall tube failure), or a loss of combustion air control (such as loss of a combustion air fan, induced draft fan, or combustion grate bar failure), then the CO limit can be exceeded for up to 15 hours per occurrence. The Florida Air Regulations have a more stringent requirement: Section 62-210.700, F.A.C. states that, "the duration of excess emissions shall be minimized, but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." The County requests that DEP authorize the use of the 40 CFR 60 Subpart Eb excess emissions durations of up to three hours per startup/shutdown/malfunction occurrence, and 15 hours per loss of boiler water level control or combustion air control, because these are more specific to MWC unit operation.

2.4.2 Incinerator NSPS (Subpart E)

The existing Facility is subject to Standards of Performance for Incinerators (NSPS Subpart E at 40 CFR 60.50 et. seq.). These standards apply to all incinerators capable of charging more than 45 metric tons per day (50 tpd) of MSW and that commenced construction or modification after August 17, 1971. Subpart E requirements are:

- Particulate matter emissions limited to 0.18 grams per dry standard cubic meter (g/dscm), equivalent to 0.08 grains per dry standard cubic foot (gr/dscf), corrected to 12 percent carbon dioxide (12% CO_2) [40 CFR 60.52(a)].

- Daily charging rates and hours of operation shall be recorded [40 CFR 60.53(a)].

- Compliance with the particulate matter emission limit shall be demonstrated by conducting a performance test as required in 40 CFR 60.8 (40 CFR 60.54).

The proposed new Unit 4 will also be subject to these requirements. However, the Subpart Eb NSPS, as discussed above, are more restrictive than the Subpart E NSPS requirements.

2.4.3 Industrial-Commercial-Institutional Steam Generating Unit NSPS (Subpart Db)

The Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (NSPS Subpart Db 40 CFR 60.40b et. seq.) apply to steam generating units that commenced construction, modification, or reconstruction after June 19, 1984, and which have a total heat input capacity of greater than 100 MMBtu/hr. The Facility's proposed new Unit 4 would have a maximum rated capacity of 250

MMBtu/hr, exceeding the 100-MMBtu/hr threshold on its own. Therefore, Subpart Db applies.

Subpart Db requirements potentially applicable to Unit 4 are:

- Particulate matter emissions are limited to 43 nanograms/joule (ng/J), equivalent to 0.10 pound per MMBtu (lb/MMBtu), for facilities that combust only municipal solid waste or municipal solid waste and other fuels if the annual capacity factor for fuels other than municipal solid waste is 10 percent or less (this standard applies at all times except during periods of startup, shutdown or malfunctions) [40 CFR 60.43b(d)].
- Nitrogen oxides emissions are limited to 130 ng/J (0.30 lb/MMBtu) for facilities that simultaneously combust natural gas with municipal solid waste unless the Facility is subject to a federally enforceable requirement that limits the annual capacity for natural gas to 10 percent or less (this standard is a 30-day rolling average which applies at all times including periods of startup, shutdown, and malfunction) [40 CFR 60.44b(d) and (h)].
- Compliance with the particulate matter and nitrogen oxides emission limits shall be determined through performance testing as required in 40 CFR 60.8 (40 CFR 60.46b).
- If subject to a nitrogen oxides emission standard in 40 CFR 60.44b, continuous emission monitoring for nitrogen oxides shall be performed, with emission measurements recorded in units of ng/J or lb/MMBtu (40 CFR 60.48b).
- Reporting and recordkeeping requirements include recording the amounts of each fuel combusted during each day and calculating annual capacity factors individually for each fuel (40 CFR 60.49b).

2.4.4 Other NSPS Subparts

The proposed new Unit 4 would not be subject to any other NSPS requirements, since there are no other NSPS subparts potentially applicable to MWC units.

2.5 National Emission Standards for Hazardous Air Pollutants

Applicability of the USEPA National Emission Standards for Hazardous Air Pollutants (NESHAPs), in 40 CFR 61, to the Facility is summarized below. These federal NESHAPS are adopted in the state regulations by reference in Section 62-204.800(9)(b), F.A.C. There are two NESHAPS that might be applicable to incinerators or MWC units.

2.5.1 Beryllium NESHAP

- The National Emission Standard for Beryllium (NESHAP Subpart C at 40 CFR 61.30 et. seq.) is applicable to incinerators which process beryllium-containing wastes. The proposed new Unit 4 is not subject to Subpart C, because Unit 4 will not burn beryllium-containing wastes, as defined in Subpart C.

2.5.2 Mercury NESHAP

The National Emission Standard for Mercury (NESHAP Subpart E at 40 CFR 61.50 et. seq.) is applicable to plants that process wastewater treatment plant sludges. Since the existing Facility, as well as the proposed new Unit 4, are prohibited from accepting sewage sludge wastes, Unit 4 is not subject to this subpart.

2.6 Maximum Achievable Control Technology (MACT) Requirements

Section 112 of the Clean Air Act controls hazardous air pollutant (HAP) emissions from major sources. A major source is one that has the potential to emit 10 tons per year of a single HAP, or 25 tons per year of any combination of HAPs. The Facility is an existing major source of HAPs.

40 CFR 63 Subpart B requires case-by-case control technology determinations, in accordance with CAA Section 112(g)(2)(B), for constructed or reconstructed major sources of HAPs, unless an emission limitation established under CAA Section 112 will be met. Florida Administrative Code (F.A.C.) Sections 62-204, 62-210, and 62-212 implement these requirements.

Unit 4 would meet the definition of a constructed major source in 40 CFR 63.41, and there is no emission limitation set under CAA Section 112 that applies to the Facility. However, 40 CFR 60 Subpart Eb NSPS for MWCs, described above, were developed under Section 129 of the CAA specifically to require MACT for HAPs, and the criteria established in the CAA for emission limitations under Section 129 [in Section 129(a)(2)] are essentially identical to the criteria established in the CAA Section 112(d)(1) and 112(d)(2) for MACT. Therefore, the Facility will be meeting a MACT standard, and no case-by-case MACT determination is necessary.

2.7 Compliance Assurance Monitoring (CAM) Rule

The Compliance Assurance Monitoring (CAM) Rule, 40 CFR 64, was written to provide a "reasonable assurance" of continuous compliance with emissions limitations or standards in cases where the underlying requirement for an emissions unit does not require continuous emissions monitoring and for units that are part of major sources that have Title V operating permits. The rule applies to a pollutant-specific emissions limit for a unit at a major source required to have a Title V permit, if the unit satisfies all of the following criteria:

1) The unit is subject to an emissions limitation, other than an exempt (defined below) emissions limitation;

2) The unit uses a control device to achieve compliance with the emissions limitation; and

3) The unit has potential pre-control device emissions of the regulated air pollutant that will equal or exceed the amount, in tons per year, required for a source to be classified as a major source (100 tons per year for criteria air pollutants and 10 tons per year for an individual HAP).

The exempt emissions limitations include any NESHAPs or NSPS proposed after November 15, 1990. (The other exemptions are not relevant to this project.)

Unit 4 will be subject to the emissions limitations of the 40 CFR 60 Subpart Eb NSPS for Municipal Waste Combustors. Since these NSPS were originally promulgated in December, 1995, they are exempt from CAM.

The Subpart E and Subpart Db NSPS predate November 15, 1990. However, their emissions limitations are for pollutants covered by Subpart Eb, and are less stringent than the Subpart Eb limits. Therefore, the requirements of CAM would be met by the Subpart Eb requirements, and a CAM plan is not necessary.

CAM may apply if there is a BACT standard that is different (either more or less stringent) than an NSPS standard. Unit 4 will have BACT-based emission limits for sulfuric acid mist and hydrogen fluoride (see Table 2-2 and Section 3), two pollutants not covered by the Subpart Eb limitations and monitoring requirements. These limits, therefore, are not exempt, so Criterion 1 applies. Unit 4's spray dryer absorber (SDA) would be a control device for these pollutants, so Criterion 2 will apply. On the assumption that the SDA could achieve 90% removal for these two acid gases, uncontrolled emissions of both pollutants would exceed their respective major source thresholds (100 tons/year for sulfuric acid mist, and 10 tons/year for hydrogen fluoride). Therefore, Criterion 3 is met, and a CAM Plan would be required for sulfuric acid mist and hydrogen fluoride emissions. The CAM Rule requires that the CAM Plan be submitted with the Title V Air Operating Permit revision for the proposed project.

2.8 Federal Aviation Administration Requirements for Objects Affecting Navigable Airspace

Federal Aviation Administration (FAA) regulations in 14 CFR 77 govern stack heights and lighting of stacks and other tall structures near airports. The rules require that the FAA be notified for any proposed new construction that:

- would be greater than 200 feet in height above ground level; or

- would be of greater height than an imaginary surface extending outward and upward at one of the following slopes:
  - 100 to 1 for a horizontal distance of 20,000 feet from the nearest point to the nearest runway with at least one runway longer than 3,200 feet;
  - 50 to 1 for a horizontal distance of 10,000 feet from the nearest point of the nearest runway with its longest runway no more than 3,200 feet in actual length.

The notification is required to be submitted to the FAA regional office on FAA Form 7560-1 Notice of Proposed Construction or Alteration. The FAA regional office then reviews the form and responds with its requirements for lighting and/or height limitations.

The tallest structure associated with the proposed project will be the existing Facility's stack, which is 67 meters (220 feet). Unit 4 will exhaust to a flue in the existing stack. Since the stack height will not be changed by the project, it will not be subject to FAA notice requirements. The FAA previously was given notice concerning the construction of the stack for Units 1-3.

2.9 Florida Air Regulations

Florida's air regulations concerning air permits are contained primarily in Rules 62-210, 62-212, 62-213, 62-296, and 62-297, F.A.C. Specifically, Section 62-210.300 F.A.C., requires appropriate permits prior to modification "to any source which emits or can reasonably be expected to emit any air pollutant...unless exempted pursuant to Department rules or statutes." Compliance with these air permit requirements are discussed in Section 2.2, above.

As discussed in Sections 2.4 and 2.5 above, NSPS and NESHAP requirements for the proposed Unit 4 are adopted, mostly by reference, into the F.A.C under 62-204.800. Other air quality requirements in the F.A.C. applicable to the proposed Facility Unit 4 are discussed below. These requirements are contained in Rule 62-210, F.A.C., which contains general requirements, Rule 62-296, F.A.C., which contains Emission Standards for Stationary Sources, or in Rule 62-297, F.A.C., which contains Emission Monitoring Requirements for Stationary Sources.

Section 62-210.700, F.A.C. limits excess emissions during periods of startup, shutdown or malfunction to no more than two hours in any 24 hour period unless specifically authorized by the DEP. As discussed in Section 2.4.1, above, the County requests that DEP authorize the use of the 40 CFR 60 Subpart Eb excess emissions durations of up to three hours per startup/shutdown/malfunction occurrence, and 15 hours per loss of boiler water level control or combustion air control, because these are more specific to MWC unit operation.

The existing Facility, and the proposed Unit 4, must meet the Florida General Pollutant Emission Limiting Standards in Sections 62-296.320(1), 62-296.320(2), 62-296.320(3), 62-296.320(4)(b), and 62-296.320(4)(c), F.A.C. The particulate and opacity emission limiting standards of Section 62-296.320(4)(a), F.A.C., do not apply to any emission units at the Facility because the MWC units are subject to particulate matter standards at Section 62-296.401, and the other emission units do not produce a finished product through a chemical or physical change.

Emission standards for incinerators are set forth in Section 62-296.401, F.A.C. Since Unit 4 will be required to meet the 40 CFR 60 Subpart Eb NSPS limits for particulate matter of 0.010 gr/dscf corrected to 7 percent O_2, Unit 4 will also comply with the Section 62-296.401(3)(a), F.A.C. requirement of 0.08 gr/dscf corrected to 50 percent excess air. Unit 4 will also comply with the Section 62-296.401(3)(b), F.A.C., requirement of no objectionable odor. Emissions monitoring requirements for incinerators are described in Section 62-297.330, F.A.C. The proposed new Unit 4 will meet the more stringent monitoring requirements under the USEPA NSPS for MWCs in 40 CFR 60 Subpart Eb.

As discussed in Section 5.0, the entire State of Florida is either classified as attainment or considered to be in attainment (i.e., unclassifiable) with respect to the Federal AAQS for all pollutants. However, the Facility is located in maintenance areas for lead, ozone, and particulate matter. Therefore, the Facility is potentially subject to Reasonably Available Control Technology (RACT) requirements for these pollutants.

The ozone maintenance area, as described in Section 62-204.340(4)(a), F.A.C., encompasses both Hillsborough and Pinellas Counties. Volatile organic compound (VOC) RACT requirements are given in Section 62-296.500 to 62-296.516, F.A.C., and in Sections 62-296.401 to 62-296.415, F.A.C. There are no VOC RACT requirements in these sections which would apply to Unit 4. The VOC and NOx RACT requirements in Section 62-296.570 are not applicable since these requirements apply only to Broward, Dade, and Palm Beach Counties, as described at Section 62 296.500(1)(b), F.A.C.

The particulate matter (PM) maintenance area, as described in Section 62-204.340(4)(b), F.A.C., subjects Unit 4 to a number of potential PM RACT requirements in Section 62-296.700, F.A.C. Emission units at the Facility with total allowable emissions of PM less than one ton per year are exempt from RACT requirements by Section 62-296.700(1)(c). Unconfined particulate matter emissions from open stockpiling of materials, vehicular traffic, and other emissions from roads and plant grounds, or construction activities, are also exempt from RACT requirements by Section 62-296.700(1)(e). Non-exempt emission units are subject to the RACT requirements in Sections 62-296.700(4) for permit content, 62-296.700(5) for circumvention, and 62-296.700(6) for operation and maintenance plans.

Specific emission limiting RACT requirements for particulate matter are given in Section 62-296.700 to 62-296.712, F.A.C., and Sections 62-96.401 to 62-296.415, F.A.C.

As noted earlier, Unit 4 will perform better than the Florida particulate matter requirements for incinerators given in Section 62-296.401(3).

Emission units at the Facility other than the MWC units are subject to the specific particulate matter emission limiting standards given in Section 62-296.711, F.A.C., for materials handling, sizing, screening, crushing, and grinding operations. These particulate matter RACT requirements are applicable to:

- Loading/unloading of materials to/from containers such as trucks and storage structures [Section 62-296.711(1)(a)].
- Non-portable conveyor systems [Section 62-296.711(1)(b)].
- Storage of materials in silos or enclosed bins with capacities of 50 cubic yards or greater [Section 62-296.711(1)(c)].

These RACT requirements would be applicable to fugitive particulate matter emissions and particulate matter emissions from the lime and activated carbon storage silos associated with Unit 4, unless exempted by virtue of PM emissions being less than one ton per year [Section 62-296.700(1)(c)].

The specific particulate matter RACT emission limitations are:

- No visible emissions (i.e., five percent opacity) [Section 62-296.711(2)(a), F.A.C.].
- Emissions exhausted through a stack or vent shall be limited to 0.03 gr/dscf or less for operations totally or partially enclosed to comply with the RACT visible emissions limits [Section 62-296.711(2)(b), F.A.C.].

The lime and activated carbon storage silos will be equipped with dust collectors (i.e., baghouses) to control PM emissions during filling operations. As part of the bid specifications for Unit 4, dust collectors with design outlet loadings of 0.015 gr/dscf for silos and ash building ventilation systems will be specified. This proposed emission limitation is more restrictive than FDEP's RACT requirements. Pursuant to Section 62-296.711(3)(c), F.A.C., the County also requests that compliance for minor sources equipped with baghouses be determined using Method 9 visible emission tests indicating no visible emissions (five percent opacity) in lieu of particulate stack tests.

Pursuant to Sections 62-296.711(2)(c) and 62-279.620, F.A.C., the County is requesting that FDEP approve the following alternative limitations as RACT for fugitive Unit 4 PM emissions based on the NSPS requirements: ash conveyors and ash storage, handling, and transfer facilities will be enclosed to minimize fugitive emissions. However, some fugitive emissions may still occur from small openings in the enclosure, from seams around access hatches, from building doors, etc. Also, maintenance and repair activities may require opening of an enclosure, which could generate short-term fugitive emissions.

USEPA recognized in the NSPS that it is not possible to eliminate all visible emissions of ash at all times. USEPA's NSPS in 40 CFR 60.55b(a) do not allow visible emissions "in excess of 5% of the observation period (i.e., nine minutes per three-hour period), as determined by EPA Reference Method 22. . ." Stated differently, visible emissions are allowed up to nine minutes per three-hour observation period. As noted in 40 CFR 60.55b(b), this standard applies to both fugitive emissions and emissions from buildings or enclosures of ash conveying systems. The standard for visible emissions does not apply during maintenance and repair activities of ash conveying systems [40 CFR 60.55b(c)]. The NSPS were developed by USEPA after spending several years studying municipal waste combustors in the United States and these limits are based on the use of Maximum Achievable Control Technology (MACT), which represents the level of performance that is attained by the best performing of all existing facilities. In light of these facts, the County requests that FDEP approve the NSPS emission limitations for fugitive ash emissions as RACT for Unit 4.

The County also requests, in accordance with Section 62-297.620, F.A.C., that compliance for fugitive ash emissions be determined using Method 22, rather than Method 9, as specified in Section 62-296.711(3)(a), F.A.C. Both USEPA methods are incorporated by reference in Sections 62-204.800 and 62-297.401, F.A.C. Since Method 22 is more appropriate for determining the frequency of visible emissions from fugitive sources when there is no need to determine the opacity level, Method 22 is more suitable to the fugitive ash emissions sources.

2.10 Florida Mercury Rule

Section 62-296.416, F.A.C. (the Florida Mercury Rule) establishes standards for mercury emissions from all MWC facilities with charging rates equal to or greater than 40 tons per day. The County is proposing to meet the standards for mercury for Unit 4 using post-combustion control equipment. Therefore, the emission standards of Section 62-296.416(3)(a), F.AC., will apply, which are that all mercury emissions shall not exceed 70 μg/dscm corrected to 7 percent O_2, or achieve 80 percent control, whichever occurs first. The more stringent of the Florida Mercury Rule or the USEPA 40 CFR 60 Subpart Eb NSPS shall apply, which are 70 μg/dscm (Florida Rule) or 85 percent control (USEPA NSPS), whichever is more restrictive. Compliance shall be determined by annual USEPA Method 29 stack tests.

2.11 Permits Requirements

2.11.1 Existing Permits

The Facility was constructed and went into operation in 1987. In 1983, the County submitted a PPSA application for construction of a new Refuse-to-Energy Facility with three 400-tpd units.

The Facility has a current Title V air operating permit, Permit No. 0570261-005-AV.

The operating permit includes the following emission limits for the existing three units:

PM	27 mg/dscm or 0.012 gr/dscf @ 7% O_2
SO_2	29 ppmdvc @ 7% O_2 or 75% reduction by weight, whichever is less stringent
NO_X	205 ppmdvc @ 7% O_2
VOC	0.01 gr/dscf @ 12% CO_2
Lead	0.44 mg/dscm @ 7% O_2
Cadmium	0.040 mg/dscm @ 7% O_2
Fluorides	6.74 mg/dscm @ 7% O_2
HCl	29 ppmdvc @ 7% O_2
CO	100 ppmdvc @ 7% O_2
PCDD/PCDF	30 ng/dscm @ 7% O_2
Mercury	70 µg/dscm @ 7% O_2
Beryllium	1.48 µg/dscm @ 7% O_2
Sulfuric Acid Mist	0.072 gr/dscf @ 12%CO_2

2.11.2 Proposed Permit Conditions

The County is requesting that the following permit conditions be granted for Unit 4:

- Section 62-210.700, F.A.C. limits excess emissions during periods of startup, shutdown or malfunction to no more than two hours in any 24 hour period unless specifically authorized by the DEP. As discussed in Section 2.4.1, above, the County requests that DEP specifically authorize the use of the 40 CFR 60 Subpart Eb excess emissions durations of up to three hours per startup/shutdown/malfunction occurrence, and 15 hours per loss of boiler water level control or combustion air control, because these are more specific to MWC unit operation. The Department's permit should explicitly state that these provisions of Subpart Eb supercede the requirements in Section 62-210.700 in these circumstances.

- The County requests that FDEP approve the NSPS emission limitations for fugitive ash emissions (40 CFR 60.55b) as RACT for Unit 4.

- The County requests, in accordance with Section 62-297.620, F.A.C., that compliance for fugitive ash emissions be determined using Method 22, rather than Method 9, as specified in Section 62-296.711(3)(a), F.A.C.

- The County requests that the VOC limit cited above for the existing Units 1-3 be deleted from the Title V permit, and that no VOC limit be set for the proposed Unit 4. 40 CFR 60 Subparts Cb (existing units) and Eb (proposed unit) do not contain VOC limits. The requirement for continuous CO monitoring in these rules is a more stringent basis on which to ensure good combustion.

2.12 Conclusions

The construction of Unit 4 is subject to review under the PSD program. The proposed Unit 4 will comply with the USEPA NSPS (40 CFR 60, Subpart Eb), Florida Mercury Rule (Section 62-296.416, F.A.C.), and all other applicable air regulations for permits and certificates.

Section 3
Best Available Control Technology Evaluation (BACT)

3.1 Introduction

This section describes the methodology and results of the Best Available Control Technology (BACT) evaluation. As described in Section 1, Hillsborough County will expand the Hillsborough County Resource Recovery Facility (the Facility) by installing a fourth municipal waste combustor (MWC) unit, which will be rated at a nominal capacity of 660 tons per day. This new unit will increase the Facility nominal capacity to 1,980 tons per day. The installation of a new MWC unit at the Facility is a major modification to an existing major stationary source in an attainment area and is subject to Prevention of Significant Deterioration (PSD) review because this change will result in an increase in pollutant emissions in excess of PSD significant emission rates. Specific pollutants with proposed emissions greater than PSD significant emission rates (see **Table 2-2**) are:

- particulate matter (PM) and particulates with a mean aerodynamic diameter less than ten microns (PM_{10}),
- sulfur dioxide (SO_2),
- carbon monoxide (CO),
- nitrogen oxides (NO_x),
- mercury (Hg),
- sulfuric acid mist (SAM),
- fluorides
- MWC metals (as PM),
- MWC acid gases, as SO_2 and hydrogen chloride (HCl), and
- MWC Organics (as volatile organic compounds (VOCs) and total tetra through octa dioxins and furans).

Consequently, the Facility is subject to a BACT evaluation for each pollutant subject to PSD review.

As part of the BACT evaluation, this section will provide a brief discussion of the applicable air quality regulations that drive the BACT evaluation, the methodology for conducting a BACT evaluation, including assessing the potential pollutant emission reductions benefits of the Hillsborough County's materials separation program, and the proposed air pollution control technology for the new MWC unit, and its associated equipment.

3.2 Description of BACT Review

In accordance with United States Environmental Protection Agency's (EPA) present policy of determining BACT (EPA, 1990), the analysis involves the identification of all applicable emission control alternatives for the pollutants subject to PSD review and any others requested by the governing regulatory agency. The control alternatives are then evaluated using a "top down" approach where they are ranked in descending order of effectiveness. A "top down" analysis first examines the most stringent or "top" control method to determine if technical considerations or potential energy, environmental, or economic impacts justify a conclusion that the control method is not BACT. If the most stringent or "top" control alternative is determined not to be BACT using this methodology, then the next most stringent alternative is considered until BACT is determined. Equipment with equivalent control capabilities does not require an evaluation. For those pollutants which have applicable air pollutant emission standards, such as New Source Performance Standards (NSPS), BACT needs to be at least as stringent as the applicable standard.

On December 19, 1995, EPA promulgated standards and guidelines for MWCs in 40 Code of Federal Register (CFR) Part 60 Subparts Eb and Cb, respectively. The NSPS under 40 CFR 60 Subpart Eb apply to each MWC unit with a combustion capacity greater than 250 tons per day (tpd) of MSW for which construction is commenced after September 20, 1994, or which modification or reconstruction is commenced after June 19, 1996. The Subpart Eb standards were developed under Section 111 (d) and 129 of the Clean Air Act (CAA). Under Section 129 of the CAA, the NSPS were also established to reflect Maximum Achievable Control Technology (MACT) and to specify emission levels for additional pollutants. Florida adopted the Subpart Eb regulations by reference in FAC 62-204.800(7). The Subpart Eb standards require states to develop regulations that would limit MWC emissions from new and modified MWCs to levels at least stringent as the federal requirement. EPA established emission limits for PM, opacity, cadmium (Cd), lead (Pb), Hg, SO_2, HCl, CO, NO_x, MWC metals, organics, acid gases and dioxins/furans. **Table 2-3** presents Subpart Eb emission limits for new or modified large MWC units. Only the Lee County Energy Recovery Facility's (LCERF) new MWC unit and the Harrisonburg Resource Recovery Facility (HRRF) have recently been permitted in the US since the promulgation of the final standards and guidelines for MWCs. Note that since the HRRF was a reconstruction project, their permit limits were not as restrictive as LCERF's permit limits. The information presented in this BACT for Hillsborough County reflect information from the LCERF approved permit, the LCERF supporting BACT determination and EPA's conclusions in establishing the final standards and guidelines for MWCS in 1995. EPA's conclusions have not changed since there has been little activity in the municipal waste combustion industry.

According to EPA's Draft New Source Review Manual, five steps need to be followed to determine BACT:

- Identify all available control technologies;
- Evaluate the technical feasibility of alternative technologies ;
- Rank remaining control technologies by control effectiveness, with the most effective control alternative at the top;
- Evaluate environmental, economic and energy impacts, and
- Select BACT.

The purpose of technical feasibility analysis is to determine whether a technology can realistically be anticipated to remove or reduce emissions of a specific pollutant from a source's exhaust. Those technologies considered technically feasible are then evaluated based on their potential energy, economic and environmental impacts or benefits. The energy impact analysis is based on whether the energy needed to apply a control technology is excessive relative to other available technologies. The purpose of the economic impact analysis is to determine the cost-effectiveness of applying a given control technology. The cost effectiveness estimates are developed as a "cost per ton of pollutant removed" for evaluating the reasonableness of various emission control technology costs. This is completed by dividing the total annual cost of each control alternative by the amount of emissions (in tons) reduced by each control alternative. Finally, the environmental impact evaluation is based on identifying both beneficial and non-beneficial environmental impacts resulting from application of a given control technology.

Development of the proposed control strategies is based on previously selected BACT evaluations for other permitted facilities and the proven capabilities of various control technologies. The EPA's BACT/LAER Clearinghouse (www.epa.gov/ttn/catc) contains a partial list of permitted municipal solid waste (MSW) facilities. Although the Clearinghouse is a principal source of information, it is not always complete. The submittal of information from state permitting agencies to the Clearinghouse is voluntary. The Clearinghouse may not contain information on recently permitted facilities, and not all of the facilities listed as MSW combustion facilities by the Clearinghouse would necessarily be similar to the proposed Facility. A listed facility may use another fuel, such as refuse-derived fuel (RDF), employ different combustion or air pollution control technologies, or operate at much lower or higher firing rates. Certain pollutant emission rates vary inversely with one another, (e.g., NO_x and CO), hence automatic reliance on the Clearinghouse for lowest permitted values for each pollutant could result in an erroneous composite being applied to a "top down" BACT analysis. A review of the database indicated that in the most recent three years (2002-2004) only three MSW facilities have submitted approved air permit applications for modifications or upgrades to their existing facilities. These facilities included Harrisonburg County, Virginia, Camden County, New Jersey and Lee

County, Florida. Of these three facilities, Lee County had the most stringent air pollutant emissions standards. In addition, the Lee County MWC unit is identical to the one proposed at the Facility. Therefore, the Lee County permit limits were used as guide for preparing the BACT evaluation. **Table 3-1** presents a summary of the permit limits at each facility.

Table 3-1
Comparison of Most Recent Municipal Waste Combustor Emission Limits and Control Technologies
EPA RACT/BACT/LAER Clearinghouse

Facility Name:	**Camden County Resource Recovery Facility, Camden, NJ**		**Harrisonburg Resource Recovery Facility, Harrisonburg, VA**		**Lee County Waste-to-Energy Facility, Lee County, FL**	
Permit No.:	**NJ-0037**		**VA-81016**		**PSD-FL-151C & 0710119-002-A**	
Date:	**3/22/2002**		**3/25/2003**		**10/13/2003**	
Combustion Unit Type:	**(4) Mass Burn Waterwall Incinerators**		**(2) Modified MWCs**		**(1) New MWC Unit (291.5 MMBtu/hr)**	
MSW Throughput:	**350 TPD per unit**		**100 TPD per unit**		**660 TPD**	
Pollutant	**Emission Limit**	**Control Technology**	**Emission Limit**	**Control Technology**	**Emission Limit**	**Control Technology**
Particulate Matter	32 mg/dscm@7%O_2 4.5 lb/hr each 0.31 lb/ton	ESP-Semi-Dry Scrubber	24 mg/dscm @7% O_2 1.68 lb/hr (each) 7.37 tpy (each)	Fabric Filter	20.6 mg/dscm @7% O_2	Baghouse
Nitrogen Oxides	5.08 lb/ton 338 lb/hr (all units)	--	160 ppmdv @7% O_2 10.25 lb.hr (each) 44.9 tpy (each)	FGR with low NOx burners & GCP	110 ppmdv @7% O_2 (12-mo rolling avg.) 150 ppmdv @7% O_2 (24-hr avg.) 60% control eff.	Non-Selective Catalytic Reduction
Sulfur Dioxide	2.36 lb/ton 138 lb/hr (all units)	--	30 ppmdv @7% O_2 5.5 lb/hr (each) 24.11 tpy (each) 80% control eff.	Dry Flue Gas Scrubbing System with hydrated lime sorbent	26 ppmdv @7% O_2 80% control eff.	Dry Scrubbers
Carbon Monoxide	4.13 lb/ton 249 lb/hr (all units)	--	100 ppmdv @7% O_2 8.03 lb/hr (each) 35.16 tpy (each)	Carbon Injection & GCP	80 ppmdv @7% O_2 (12-mo rolling avg.) 100 ppmdv @7% O_2 (4-hr avg.)	Equipment Design & GCP
Cadmium	0.0002 lb/ton 0.0140 lb/hr	--	0.02 mg/dscm @7% O_2	GCP	--	--
Mercury	0.005 lb/ton 0.31 lb/hr	--	0.08 mg/dscm @7% O_2	Carbon Injection & GCP	0.028 mg/dscm @7% O_2 85% control eff.	Carbon Injection
[illegible]	0.006 lb/ton 0.333 lb/hr	--	0.2 mg/dscm @7% O_2	GCP	--	--
Arsenic	0.0 lb/ton 0.0021 lb/hr	--	--	--	--	--
Beryllium	0.0 lb/ton 0.0001 lb/hr 0.086 lb/hr	--	--	--	--	--
Nickel	0.0012 lb/ton 0.072 lb/hr	--	--	--	--	--
Chromium	0.0015 lb/ton 0.086 lb/hr	--	--	--	--	--
Hydrogen Chloride	1.21 lb/ton 70.5 lb/hr	--	25 ppmdv @7% O_2 2.58 lb/hr (each) 95% control eff.	Dry Flue Gas Scrubbing System with hydrated lime sorbent	25 ppmdv @7% O_2 95% control eff.	Dry Scrubbers
H_2SO_4	0.18 lb/ton 10.4 lb/hr	--	--	--	15 ppmdv @7% O_2 15 lbs/hr	
Hydrogen Fluoride	0.026 lb/ton 1.5 lb/hr	--	--	--	3.5 ppmdv @7% O_2	Dry Scrubbers
Nonmethane Hydrocarbons	0.2 lb/ton 27 lb/hr	--	--	--		
PAH	0.001 lb/ton 0.058 lb/hr	--	--	--		
PCDD/PCDF	0.0 lb/ton 0.0 lb/hr	--	13 ng/dscm @7% O_2	Carbon Injection & GCP	13 ng/dscm @7% O_2	Furnace Design/ Temperature Control
Volatile Organic Compounds	--	--	0.42 lb/hr (each) 1.84 tpy (each)	GCP		
Visible Emissions			10% Opacity		10% Opacity	
Fugitive PM (ash)			5% Opacity			
Metals	--	--	--	--	20.6 mg/dscm @7% O_2	Baghouse

3.3 Proposed Control Technologies

Hillsborough County (County) proposes the following control technologies to reduce air pollutant emissions from the new MWC:

- Acid gases such as SO_2, MWC acid gases (SO_2, HCl, and HF), and SAM will be controlled with a spray dry absorber (SDA) in combination with the fabric filter (FF).
- PM_{10} as well as MWC Metals (as PM_{10}) will be controlled with a high efficiency FF baghouse.
- NO_x will be controlled with a combination of Selective Non-Catalytic Reduction (SNCR) and Flue Gas Recirculation (FGR).
- GCP will provide maximize burnout of products of incomplete combustion such as CO, volatile organic compounds (VOCs), and trace organics (PCDD/PCDF).
- Activated carbon injection system in combination with flue gas cooling in the spray dry absorber (SDA) and particulate control in the FF for control of Hg.

Table 3-2 presents a summary of the BACT evaluation for each pollutant.

3.4 Materials Separation

Hillsborough County intends to meet or exceed the 30 percent recycling goal set by the state of Florida. The County has been successful in consistently achieving this goal during the last few years. Recycling is a crucial component of the County's integrated waste management system. The County achieves a considerable portion of its materials diversion and recycling by special collection of certain recyclable materials separated by the resident or business. The County also mandates the separation of yard waste. Franchise haulers collect recycled materials curbside in residential areas of the unincorporated portion of the County. The County also maintains collection facilities where County residents and business can drop off many types of recyclable items including glass, paper, plastic, cardboard, motor oil, white goods, household hazardous waste, tires, and electronic waste. The County also recycles construction and demolition (C&D) debris.

The County provides weekly, curbside pickup of recyclables to all residents in the unincorporated portion of the County through private franchise contractors. The County also provides recycling bins to residents for easy separation of paper, glass, metal and plastic. Two privately owned materials recovery facilities accept and process these materials. These facilities will accept a variety of recyclable materials, including aluminum cans, glass bottles and jars, multiple types of paper, wood waste, tin cans, cardboard, plastic bottles, Christmas trees, and some yard waste. The curbside recycling program collects approximately 30,000 tons of recyclables each

Table 3-2

Summary of Hillsborough County Resource Recovery Facility New MWC Unit Best Available Control Technology Determination

Pollutant	Control Technology	Technology Ranking	Control Efficiencies	Technology Evaluation	Economic (Total Capital Investment)	Energy	Environmental	Cost Per Ton of Pollutant Removed	Selection
Sulfur Dioxide & Acid Gases	Wet Scrubber	1	SO_2: 90-95%; Acid gases (HCl & HF) 95-99%	Primarily used in European MWCs. Typical applications uses a two-staged scrubber allows for removal of HF and HCl with water in 1st stage and using an alkaline reagent in the 2nd scrubber for SO_2 control. Disadvantages include: only moderately effective in controlling heavy metals and organic emissions, liquid effluent treatment, corrosion problems, and visible water vapor plumes.	--	--	--	--	
Sulfur Dioxide & Acid Gases	Semi-Dry Absorption/Fabric Filter (SDA/FF)	2	SO_2: 85-95%; Acid gases (HCl & HF) 95-99%	SDA scrubbers effectively control SO_2 and acid gases and have been applied to the majority of MWC facilities in the U.S. SDA scrubbers are also designed to control organics and volatile metal emissions. Ff generally preferred over ESP in combination with SDA. Disadvantages include: clogging of spray nozzles, accumulation of reagent on scrubber walls, requires large quantities of sorbent, and larger installation space than wet scrubbers.	--	--	--	--	BACT
Sulfur Dioxide & Acid Gases	Dry Sorbent Injection (DSI)	3	SO_2: 50-90%; Acid gases (HCl & HF) 90-95%	There are several types of DSI techniques (furnace, economizer, duct and hybrid) for controlling acid gas emissions for conventional MWCs. FF generally preferred over ESP in combination with DSI. Ideal for retrofitting older combustion facilities. Disadvantages include: requires large quantities of hydrated lime which is more expensive than pebble lime. more scrubber waste than SDA; more frequent FF cleaning; lower SO_2 removal than SDA.	--	--	--	--	
Sulfur Dioxide & Acid Gases	DeSONOx	4	--	DeSONOx process is a flue gas purification process during which NO_x and SO_2 are simultaneously extracted. Combination of catalysts for NOx control by NH_3 and oxidizing catalysts to convert SO_2 to SO_3. Primarily marketed for low SO_2 concentration flue gas streams, and it has not been applied to large-scale facilities. Considered an experimental technology.	--				
Particulate Matter/Metals	Fabric Filter (FF)	1	0.009 grains/dscf @7% O_2	U.S. EPA considers both FF and ESPequivalent in providing control of PM.	--	--	--	--	BACT
Particulate Matter/Metals	Electrostatic Precipitator (ESP)	2	0.009 grains/dscf @7% O_2	U.S. EPA considers both FF and ESP equivalent in providing control of PM.	--	--	--	--	
Nitrogen Oxides	Selective Catalytic Reduction (SCR)	1	50-90%	Has been applied to MWCs in Europe, Asia and Canada. In "hot-side" application (pre-PM removal device), the catalyst is fouled by HCl, metals and high PM loadings. In "cold-side" application (post-PM removal device), flue gas is clean of contaminants, but catalysts do not perform well at lower temperatures which requires reheating gas at a higher energy cost and adding pollutant emissions to flue gas.	$22,985,000	$298,000	405 tons removed	$14,100	
Nitrogen Oxides	Selective Non-Catalytic Reduction (SNCR) with Flue Gas Recirculation (FGR)	2	35-60%	SNCR using direct injection of aqueous ammonia in the MWC. NH_3 emissions may result if NH_3 is injected outside desired temperature range at a higher than normal rate, causing ammonium chloride to form stack plumes and possible corrosion of boiler tubes. Has been applied to MWCs in U.S., with FGR.	$3,050,000	$36,000	324 tons removed	$2,400	BACT
Nitrogen Oxides	Ecotube	3	possible 60%	Ecotube essentially consists of one or more retractable rotating lances (3 to 7 meters long) located just above the primary combustion zone. The lances are designed to inject high velocity air, ammonia or urea through nozzles into the upper combustion zone of the furnace. There is serious question as to how the rotating lances would survive in the combustion zone of the furnace.	--	--	--	--	
Nitrogen Oxides	Good Combustion Practices/Low Excess Air (GCP/LEA)	4	20-50%	Effective but also could increase CO, HC and PICs emissions and lower combustion efficiency	--	--	--	--	
Nitrogen Oxides	Flue Gas Recirculation (FGR)	5	10-25%	Somewhat effective, but the relatively moist flue gas from after the baghouse in combination with GCP may lead to increased emissions of CO and boiler corrosion problems.	--	--	--	--	
Nitrogen Oxides	Gas Reburning	6	Unknown	Combined with LEA/FGR achieved up to 60-70% NOx control during MWC pilot-scale study and 60% NOx control at Olmstead, MN MWC study. However, has not been applied to MWCs in U.S.	--	--	--	--	
Nitrogen Oxides	Wet Flue Gas Denitrification (FGD_n)	6	Unknown	FGD_n oxidation-reduction converts NO to NO_2 by spraying an oxidant, such as ozone into flue gas stream ahead of wet scrubbers. Produces liquid effluent that is difficult and expensive to treat. Has not been applied to MWCs in U.S.	--	--	--	--	

Summary of Hillsborough County Resource Recovery Facility New MWC Unit Best Available Control Technology Determination

Pollutant	Control Technology	Technology Ranking	Control Efficiencies	Technology Evaluation	Economic (Total Capital Investment)	Energy	Environmental	Cost Per Ton of Pollutant Removed	Selection
Nitrogen Oxides	E-Beam	6	Unknown	E-Beam reacts NH_3 or lime using a high-intensity E-Beam emitted across the flue gas by an electron gun. Reaction takes place in a steel vessel with a concrete shell. Has not been applied to MWCs in U.S.	--	--	--	--	
Nitrogen Oxides	Prism	6	Unknown	Prism is a combustion process modification which consists of a prism shaped, water-cooled structure located just above the grate of a MWC. Prism provides more uniform flue gas temperature and oxygen distributions across the furnace and lower maximum temperatures at the furnace outlet. When used in combination with SNCR, Prism's main benefit is lower ammonia consumption. Its overall impact on NOx control is limited and it appears that other less costly furnace modifications such as FGR can accomplish similar results.	--	--	--	--	
Nitrogen Oxides	Water Cooled Grates	6	Unknown	This technology has been used for a number of years. The drawback of WC grates is that they lower combustion efficiency, but when used in combination with SNCR, WC grates reportedly reduce baseline NOx emissions and reduce ammonia usage. There is no data to support the theory that the beneficial effect of WC grates and FGR are additive. WC grates is judged to be another means of enhancing SNCR but does not appear to offer any improvement over FGR either singularly or in combination with FGR.	--	--	--	--	
Nitrogen Oxides	SCONOx	6	Unknown	SCONOx is a catalytic control method for NO_x without using NH_3 as a reagent. It has been applied to clean-fired combustion equipment, such as natural gas-fired boilers and turbines. However, it has not been applied to MWCs in U.S. Catalyst could experience fouling from trace materials in flue gas.	--	--	--	--	
Carbon Monoxide	Thermal Oxiders	1	90 percent control	Themal oxidizers successfully applied to industrial sources, but not on MWC units in U.S In addition, thermal oxidizers generate increased electrical energy and fan power demands, and produce secondary pollutant emissions.	--	--	--	--	
Carbon Monoxide	Good Combustion Practice (GCP)	2	80 ppmdv @ 7% O_2	Continuous compliance with CO limit; a load limit and a temperature limit at the inlet of PM control device. No adverse environmental impacts.	--	--	--	--	BACT
Carbon Monoxide	Oxidation Cataylyst	3	--	Oxidation catalyst installed on natural gas combustion turbines; however, could be quickly poisoned by trace contaminants in MSW flue gas. Technically infeasible option.	--	--	--	--	
MWC Organics	Thermal Oxiders	1	--	Themal oxidizers successfully applied to industrial sources, but not on MWC units in U.S. In addition, thermal oxidizers generate increased electrical energy and fan power demands, and produce secondary pollutant emissions.	--	--	--		
MWC Organics	Good Combustion Practice (GCP)	2	VOCs 0.1 lb/ton Dioxin 13 ng/dscm @ 7% O_2	Continuous compliance with CO limit; a load limit and a temperature limit at the inlet of PM control device. No adverse environmental impacts.	--	--	--		BACT
MWC Organics	Oxidation Cataylyst	3	--	Oxidation catalyst installed on natural gas combustion turbines; however, could be quickly poisoned by trace contaminants in MSW flue gas. Technically infeasible option.	--	--	--		
Mercury	Activated Carbon Injection (ACI)	1	85 percent control	Activated carbon with a semi-dry scrubber system consisting of SDA and FF removes 85 percent of Hg emissions. In addition, tests shown that dioxins and furans emissions reduced by 95 to 98 percent with ACI followed by SDA/ESP.	--	--	--		Top BACT
Mercury	Wet Scrubbers	2	possible 90 percent control	Wet scrubber systems for mercury control applied to European MWCs. Soluble species of mercury compounds ($HgCl_2$ and HgO) can be captured at 90 percent or greater;however, if significant elemental Hg in flue gas, collection efficiencies limited. Disadvantages include: treating wastewater before disposal and possible release of more toxic dioxin and furan congeners.	--	--	--	--	
Mercury	Carbon Filter Beds	3	--	Three types of filter beds (cross flow, counter- current flow, and counter-cross flow). Developed in Europe as final cleaning stage to remove Hg, dioxins and furans, and acid gases. No data available proving that carbon filter bed mercury removal is better than ACI with SDA/FF.	--	--	--	--	

year. Commercial recycling is voluntary in Hillsborough County. Currently, businesses are responsible for delivering their own recyclables to the appropriate facilities.

While certain materials separation efforts could potentially reduce air emissions, the amount of emissions reductions cannot be quantified. Also, there is no evidence to demonstrate that source separation of certain components by itself provides for consistent and measurable reductions of pollutant emissions. Therefore, source separation does not qualify as BACT and will not be further evaluated in this section.

3.5 BACT Review for Sulfur Dioxide, MWC Acid Gases, Fluorides and Sulfuric Acid Mist

The combustion of MSW generates acid gases which include SO_2, MWC acid gases, such as HCl and hydrogen fluorides (HF), and SAM. Acid gases are generated in the combustion unit due to chemical reactions between the sulfur, chlorine, fluorine, and other compounds in MSW and combustion air. Scrubber systems are the most effective control technology currently available to reduce acid gas emissions from MWC units. These scrubber systems include wet, semi-dry, and dry applications. A description of each control technology is presented below.

3.5.1 Emission of Gaseous Sulfur Compounds and Acid Gases

The sulfur which contributes to pollutant emissions from solid waste combustion is chemically bound to other compounds. During combustion, a fraction of these elements escapes from the furnace as gaseous sulfur compounds while the remainder leaves as bottom or fly ash. The type of sulfur compounds released from the furnace is dependent on the presence of other gaseous compounds, combustion temperatures, and chemical (oxidizing or reducing) conditions in the furnace. Furnace conditions (oxidizing or reducing) directly influence the types of sulfur compounds which may form and exit during combustion. Excess oxygen conditions, typical of a solid waste combustor, generally result in the formation of SO_2 and SO_3, while reducing (oxygen deficient) conditions result in hydrogen sulfide (H_2S), carbonyl sulfide (COS) and elemental sulfur. Since Unit 4 will be operated under excess oxygen conditions, reduced forms of sulfur are not likely to form, and hence emissions of reduced sulfur compounds will be negligible.

Various sulfur compounds are produced from direct combustion processes. SO_2 is the predominant form of sulfur compound released from the municipal solid waste combustion process. Some of the SO_2, when released into the ambient environment, reacts with atmospheric water vapor to form sulfuric acid. Sulfuric acid and emitted sulfuric acid mist may further react in the atmosphere to form sulfate salts, a particulate aerosol.

Chlorine, and fluorine are also chemically bound to other compounds. A portion of these substances are also released during combustion and escape the furnace in various forms. Similar to sulfur, emitted chlorine and fluorine react with water vapor to form HCl and HF. The presence of these acid gases in the atmosphere results in reduced visibility, material corrosion, sensitive organ irritation in humans and animals, and can add to acid rain/fog problems.

3.5.2 Available Control Technologies

The emissions of SO_2 and acid gases from solid waste combustion can be reduced through the application of acid gas scrubbing devices. There are three general types of acid gas scrubbers offered by the air pollution control industry: wet scrubbers, dry scrubbers, and dry injection scrubbers. Although the specific operation of each of these scrubbers differs significantly, each incorporates the use of an alkaline reagent to neutralize acid gases in the flue gas stream. Wet scrubbers and dry scrubbers subject flue gas to a sorbent water solution while dry injection scrubbers inject completely dry sorbent into the flue gas.

The relative removal efficiencies of these technologies for SO_2, HCl and HF are shown in **Table 3-3**. As the table shows HCl and HF are generally better controlled than SO_2 because they are highly reactive acids. The higher removal efficiencies of dry scrubbers and wet scrubbers, in contrast to the dry injection scrubber, can be attributed to their lower operating temperatures and to their liquid-gas contact which provides better mass transfer of gaseous pollutants to the absorbing interface.

A scrubber's ability to achieve consistent and continuous control of these pollutants is better represented by the values in the lower end of the control efficiency ranges noted in **Table 3-3**.

Table 3-3
Control Efficiencies of Sulfur Dioxide and Acid Gas Control Technologies[a]

Pollution Control System	Achievable Removal Efficiencies	
	SO_2	Acid Gas (HCl and HF)
Wet Scrubber	90-95%	95-99%
Spray Dryer	85-95%	95-99%
Dry Injection Systems	50-90%	90-95%

Source: [a]Air Pollution Engineering Manual (Davis, W.T., 2000)

In addition to scrubber devices, another control system that has been tested and/or employed in various forms uses a catalytic method of SO_2 control. These technologies are described in the following review of control alternatives for the proposed Unit 4.

3.5.2.1 Wet Scrubbing Systems

Wet scrubbers have been used on refuse combustion facilities in the past primarily as particulate control devices; however, they can also be designed to provide effective acid gas control. Acid gas wet scrubbers differ from particulate matter removal wet scrubbers in several ways. The dominant mechanisms by which particulate are collected in a wet scrubber is inertial impaction of the particulate with the fluid which is dependent on the pressure drop across the unit. Therefore, particulate control wet scrubbers are typically high energy units with large pressure drops. In contrast, the process which governs the overall rate of acid gas absorption and control in a wet scrubber is the diffusion of an acid gas molecule into a liquid alkaline droplet for a reaction to occur. The design of an acid gas wet scrubber reflects this governing process since the emphasis is to increase the contact time of the liquid and gas, and the chemical composition of the liquid.

Wet scrubbers for acid gas control use an alkaline liquid which may consist of either caustic soda (sodium) solution or lime slurry (calcium) to scrub the flue gases. In larger systems, the use of lime slurry is common since the cost of the alkali favors using the less expensive lime instead of caustic soda in spite of the higher capital costs involved. Lime slurry systems react with the SO_2 and other acid gases to form calcium based salts which require clarifying, thickening, and vacuum filtering to avoid a concentration build-up of precipitated salts in the system. Sodium-based systems produce a liquid waste with highly soluble sodium based salts which may require the use of large, carefully contained, holding pond(s) or wastewater treatment plants. The holding pond(s) are used to evaporate and concentrate the dissolved salts, therefore, they are feasible in warmer climates.

Currently, wet scrubbers are operating on numerous sources in the U.S., predominantly high sulfur fuel (coal and oil) fired power plants, municipal sludge combustors, and hazardous waste combustors. Wet, calcium-based FGD systems have been the preferred acid gas control option for large utility power plants. However, wet scrubbers have not gained popularity in the U.S. waste-to-energy industry. Municipal waste combustion plants in the U.S. have predominantly utilized dry or semi-dry FGD systems in combination with a FF baghouse to minimize water use and for enhanced fine particulate control (RTP, 2003).

The bulk of recent wet scrubber experience with municipal waste combustion systems and thus, municipal waste combustion flue gas cleaning systems, comes primarily from Europe. European facilities equipped with wet scrubber systems include the Kiel and Krefeld facilities in West Germany. The Kiel plant was the first refuse burning facility in West Germany to have used electrostatic precipitators (ESPs) in combination with a single stage wet scrubber. Acceptance testing data for the original wet scrubber at the Kiel plant showed HCl and HF removal efficiencies of greater than 95 percent. In addition, emissions of sulfur oxides (SO_2 and SO_3) were reduced by approximately 50 percent (CARB, 1984). The Kiel plant demonstrated high on-line reliability for continuous operation (Beaumont Environmental, Inc. (BEI), 1986). However, the lower SO_2 removal efficiency relative to the higher HF and HCl removal efficiencies shown at the Kiel facility identified a problem with single-stage scrubbing utilizing a calcium based sorbent for acid gas control. The performance of wet scrubbers is dependent on many factors, and at the time, the data base was too limited on MWC applications for detailed evaluations of the effects.

The Krefeld plant, built soon after the Kiel plant was similar in design to the Kiel facility, except that it incorporated two-stage wet scrubbers. Each stage uses a different alkaline reagent in the scrubber solution. The first stage uses calcium hydroxide to reduce emissions of gaseous HCl and HF. Emissions of sulfur oxides are reduced in the second stage through use of either a sodium or calcium based reagent (CARB, 1984). Results from tests conducted on the Krefeld facility showed an optimum 99 percent or greater HCl removal, 97 percent or greater HF removal and 96 percent or greater SO_2 reduction when firing refuse only (BEI, 1986).

The major advantage of an acid gas wet scrubber system over either a dry scrubber or a dry injection scrubber system is its high abatement efficiency. Data on a limited number of European installations show that acid gas wet scrubbers are very efficient and can achieve removal rates of SO_2 and acid gases that are greater than or equal to those of dry scrubbers.

Although wet scrubbers may provide very effective SO_2 and other acid gas control, the technology has several disadvantages which discourage its use on solid waste combustion facilities. In addition, to the extensive and expensive liquid effluent treatment required, wet scrubbers produce a saturated gas which increases the potential corrosion of wet scrubber internals and downstream equipment. It also creates an aesthetically displeasing visible water vapor plume. The Kiel facility combustor unit has as wet scrubber which confirms these corrosion problems. The facility has been reported to have experienced severe corrosion of the wet scrubber's internals and the stack.

Other disadvantages of wet scrubber systems include:

- Wet scrubbers alone are only moderately effective in controlling heavy metals and organic emissions. Generally, ESP's are used in conjunction with wet scrubbers for added particulate removal (Davis, W.T., 2000).
- Fabric filters are not typically used with wet scrubbers due to the detrimental effect of saturated moisture on the filter bags (Davis, W.T., 2000).
- The results of several test studies regarding the ability of wet scrubbers to remove additional pollutants at municipal waste combustion facilities indicated that although there may be a reduction in the mass rate of organics, the overall dioxin/furan toxicity of the emission increases (Franklin Associates, 1991).
- Wet scrubbers are generally not effective in controlling submicron aerosol mists which would include SAM or volatilized mercury vapor (Franklin Associates, 1991).

Because of these significant technical disadvantages, the wet scrubber alternative is not considered a viable means of acid gas control, and no further analysis of this option was performed. A more detailed analysis of various control options focuses on those technologies with fewer restricting features.

3.5.2.2 Dry Scrubbers

Dry scrubbers, also referred to as wet-dry, spray dryer, semi-dry, or spray dry scrubbers, offer an effective and practical means of controlling acid gas emissions from solid waste combustion facilities. Of these types of dry scrubbers, semi-dry sorbent systems (SDA) have been applied to the majority of MWC units in the U.S. in the last ten years, and have been the technology of choice for retrofit to existing municipal waste combustors to meet the emission guidelines acid gas removal requirements.

During operation of a dry scrubber system, the flue gases from the boiler are introduced into an absorbing chamber where the gases are contacted by a finely atomized alkaline lime slurry. Acid gases are absorbed by the slurry mixture and the alkaline component reacts with the gases to form salts. Evaporation of the water produces a finely divided particle of mixed salt and unreacted alkali and flue gas having a lower temperature. A portion of the dry powder drops to the bottom of the scrubber vessel while the flue gases, containing the remaining powder with reacted acid gas salts and the particulates generated during solid waste combustion, are delivered to the particulate collector (FF or ESP) for removal.

To form the lime slurry, pebble lime (CaO) is hydrated by slaking with water ($Ca + H_2O \rightarrow Ca(OH)_2$). The slurry and any additional cooling water which may be required are then pumped to nozzles or a rotary atomizer located inside the scrubber's contact chamber. The slurry contains greater than the stoichiometric quantity of lime required to neutralize the SO_2 and acid gases in the flue gas.

Most SDA systems used to date have employed either a rotary-type atomizer or a dual fluid nozzle with an external or internal mixing design. The type of atomization system has pros and cons; however, both are capable of meeting performance specifications. Rotary designs have the following benefits:

- Better control of droplet size.
- Less energy needed for equivalent atomization at certain sizes.
- Higher throughput per single component.
- Longer lifespan of atomization component.

The dual-fluid nozzle designs also offer advantages, including:

- No moving parts – easier to operate and maintain, and less expensive.

- Compact unit allowing for easier installation and inspection during normal operations.
- Flexible installation – mounting may be vertical or horizontal.
- Flexibility – flow from a failed nozzle can be re-directed through others in the absorbing chamber while it is replaced, thus preventing the loss of operating time and providing on-line maintenance.

In the absorbing chamber the water in the slurry droplets is rapidly evaporated by the hot flue gases. SO_2 and other acid gases are absorbed onto the hydrated lime particles and react to form calcium salts. The reduction in flue gas temperature provided by the evaporating water has been shown to be a major factor influencing the removal of acid gases. Studies such as the 1986 Environment Canada Study (R. Klieius et. al., 1987) have shown that SO_2 and other acid gas removal efficiencies are significantly higher when the scrubber is operated at temperatures approaching the saturation temperature of the flue gas. As a result of the scrubbing process a dry, free-flowing powder is produced consisting of unreacted lime, salts (most prevalent being $CaCl_2$, $CaSO_3$ and $CaSO_4$), and flyash. The largest of these particles are separated by gravity from the gas in the absorbing chamber by gravity and fall to the bottom. The smaller particles are carried to the PM control device for separation from the flue gas.

The FF is generally preferred over the ESP in combination with SDA because of its inherent high efficiency and especially because of its greater secondary reaction capability. This secondary reaction capability relates to the creation of a porous filter cake on the FF bags which contains both spent and unspent reagent. This filter cake is credited with controlling pressure drops, dampening surges or pollutant spikes, providing a site for increased reagent utilization, and increasing equipment reliability (BEI, 1986).

The results of a performance summary of SDA/FF on several facilities supported the use of a SDA/FF as a means of controlling several pollutants in addition to MWC acid gases. Factors affecting acid gas removal by SDA/FF systems include stoichiometric ratio, SDA outlet temperature (FF inlet), and inlet SO_2 concentration to the SDA. A stoichiometric ratio in excess of three is generally necessary to obtain consistently high acid gas removal efficiencies of 90 percent SO_2 and 98 percent HCl. Suppliers have claimed that SDA/FF systems are capable of achieving 90 percent or greater SO_2 and 95 percent or greater HCl removal efficiencies (EPA, 1989a and EPA, 1995d). Three years of data (2000-2002) from the existing Hillsborough County facilities have demonstrated the ability to consistently achieve this performance level.

The major disadvantages of SDA systems include potential clogging of atomizers or spray nozzles and reagent accumulation on the dry scrubber walls. A dry scrubbing system also requires a relatively greater quantity of sorbent and a relatively larger installation space than does a wet scrubbing system.

The significant performance advantages of a dry scrubber system far outweigh its disadvantages. The major advantages include:

- SDA systems provide effective SO_2 and other acid gas control. With the use of an efficient particulate control device, dry scrubbers, unlike wet scrubbers, also have the ability to reduce emissions of organics and metals.
- Unlike a wet scrubber, a SDA system produces a dry waste which is easier to handle and dispose.
- SDA exhaust streams are not saturated, and therefore, the potential for corrosion is greatly reduced when compared to a wet scrubber. Flue gas reheating, which would increase energy costs, is not required to prevent a saturated plume.
- Unlike a wet scrubber, a SDA system may be easily used with currently available particulate control devices.
- Unlike a wet scrubber, a SDA system uses a small amount of water, which evaporates and does not require treatment.

In developing and promulgating the MWC NSPS, the EPA concluded that SDA/FF systems are the best demonstrated control technology for reducing MWC facility emissions of acid gases, particulate matter and metals, and providing additional control of MWC facility organic emissions. This conclusion is based on operating data from a number of operating modern MWC facilities (EPA, 1989b and EPA, 1995d).

3.5.2.3 Dry Sorbent Injection (DSI)

Sorbent injection system can be divided into four types. These are:

- Furnace sorbent injection;
- Economizer sorbent injection;
- Duct sorbent injection, and
- Hybrid sorbent injection.

The simplest technology is furnace sorbent injection where a dry sorbent is injected into the upper part of the furnace to react with the SO_2 in the flue gas. The finely grained sorbent is distributed quickly and evenly over the entire cross section in the upper part of the furnace in a location where the temperature is in the range of 750-1,250°C (1382-2282°F). Commercially available limestone ($CaCO_3$) or hydrated lime ($Ca(OH)_2$) is used as sorbent. While the flue gas flows through the convective pass, where the temperature remains above 750°C (1382°F), the sorbent reacts with SO_2 and O_2 to form $CaSO_4$. This is later captured in a fabric filter or ESP together with unused sorbent and fly ash. Removal efficiency of up to 50 percent can be obtained; with some studies indicating up to 95 percent removal is achievable under the right operating and sorbent mix (IEA Clean Coal Centre, 2004). Potential disadvantages of furnace sorbent injection include fouling and erosion of convective heat transfer surfaces by the injected sorbent (EPA 1989a).

In an economizer sorbent injection process, hydrated lime is injected into the flue gas stream near the economizer zone where the temperature is in the range of 300-650°C (572-1202 °F). Wang and others (1993) reported the results of an experimental study of the process. They found that in contrast to the furnace sorbent injection process, where the reaction temperature is around 1100°C (2012°F), $Ca(OH)_2$ reacts directly with SO_2 since the temperature is too low to dehydrate $Ca(OH)_2$ completely. In this temperature range, the main product is $CaSO_3$ instead of $CaSO_4$ and the reaction rate is comparable to or higher than that at 1100°C (2012°F). The production of carbonate in the process is undesirable, since it not only consumes the sorbent but also blocks the access of SO_2 to active sorbent surfaces. The tests showed that carbonation significantly increased with reaction temperature (IEA Clean Coal Centre, 2004).

Economizer injection of sorbent appears useful for SO_2 removal, especially for retrofit projects. However, this control method has not been proposed or demonstrated on modern municipal waste combustion facilities in the U.S. In addition, interaction of the hydrates with trace contaminants in MSW combustion flue gas is not completely understood. Because of the lack of available operational data, this experimental control option cannot be entirely assessed. Therefore, this method is not considered further in this BACT evaluation.

In duct sorbent injection, the aim is to distribute the sorbent evenly in the flue gas duct after the preheater where the temperature is about 150°C (302°F). At the same time, the flue gas is humidified with water if necessary. Reaction with the SO_2 in the flue gas occurs in the ductwork and the by-product is captured in a downstream filter. Removal efficiency is greater than with furnace sorbent injection systems. An 80 percent SO_2 removal efficiency has been reported in actual commercial installations (IEA Clean Coal Centre, 2004).

There are many factors, which influence the performance of a duct sorbent injection process. These include sorbent reactivity, quantity of injected sorbent, relative humidity of the flue gas, gas and solids residence time in the duct, and quantity of recycled, unreacted sorbent from the particulate control device. Finally, when designing a duct sorbent injection system, a good working knowledge of the flow conditions in the flue gas ductwork is important. The easiest and most efficient way of achieving this is to ensure well-controlled flow conditions. As the process needs reaction time, the most obvious solution would be to establish a dedicated reaction chamber. However, even a simple reaction chamber can contribute prohibitively to the capital costs of such a process (IEA Clean Coal Centre, 2004).

The hybrid sorbent injection process is usually a combination of the furnace and duct sorbent injection systems aiming to achieve higher sorbent utilization and greater SO_2 removal. Various types of post furnace treatments are practiced in hybrid systems, such as injection of second sorbents such as sodium compounds into the duct, and humidification in a specially designed vessel.

Humidification reactivates the unreacted CaO and can boost SO_2 removal efficiency up to 90 percent depending on the process. The hybrid process offers the following advantages:

- Relatively high SO_2 removal;
- Low capital and operating costs;
- Easy to retrofit;
- Easy operation and maintenance with no slurry handling;
- Reduced installation area requirements due to compact equipment; and
- No wastewater treatment.

Although hybrid sorbent injection has been successfully applied in coal-fired boiler applications, this control method has not been proposed or demonstrated on modern municipal waste combustion facilities in the U.S. (IEA Clean Coal Centre, 2004). Therefore, this control option cannot be fully evaluated, and is not considered further in this BACT evaluation.

Greater acid gas control can be achieved by combining the DSI system with an FF rather than an ESP. Collected particulate builds up on the FF bags forming a filter cake. The presence of unreacted sorbent in the filter cake provides additional acid gas removal. FFs may also provide additional control of metals through control of fine particulate (EPA, 1989a).

An analysis of performance of DSI/FFs at several facilities, including Dutchess County, New York; Claremont, New Hampshire; Quebec City, Canada; and Wurzburg, West Germany indicated that up to 90 percent SO_2 and 95 percent HCl removal efficiency has been demonstrated with an FF inlet temperature of 250°F (121°C) and increased stoichiometric ratio of lime to acid gas. The ability to achieve these removal levels consistently has not yet been documented. The results also showed that outlet PM concentrations averaged 0.01 gr/dscf or lower at the tested DSI/FF systems. Removal efficiency for metals was available for only one facility. Removal efficiencies were estimated for other facilities based on measured outlet concentrations. Removal efficiencies for Pb, Cd, and As were estimated to average 99 percent or better. Estimates of removal efficiencies for chromium (Cr) and nickel (Ni) ranged from 94-99 percent. Removal efficiencies for Hg ranged from zero control to 99 percent control and appeared tied to the FF inlet temperature. Removal of dioxins and furans also appeared dependent on the FF inlet temperature, showing decreased emissions with temperature decrease. At less than 300°F (149°C), emissions were below 7.7 ng/dscm at 7% O_2 (EPA, 1989a).

Because the dry sorbent can be injected directly into existing furnace or duct work, capital costs for installation of the system are minimal. Therefore, a dry injection scrubber may be ideal for retrofitting older combustion facilities which have no acid gas control and where control goals are modest.

The disadvantages of a dry injection scrubber system for use on a new MWC unit are:

- Dry injection scrubbers require the use of large quantities of hydrated lime which is more expensive than the pebble lime used for dry scrubbers. The larger amount of sorbent is necessary in order to meet NSPS SO_2 removal requirements. Therefore, the operating cost differential resulting from the poor reagent use for a dry injection scrubber is significant.
- More scrubber waste is produced by a dry injection scrubber in comparison to a dry scrubber system because of the large quantitities of sorbent which must be injected.
- The residual alkalinity of the waste from a dry injection scrubber may require special handling.
- The use of a larger quantity of sorbent than that used in a dry scrubber system results in the need for more frequent fabric filter cleaning which accelerates wear-out of the filter bags.
- The increased solids loading and altered properties of the particulate matter may result in decreased particulate control device efficiency (Offen, McElroy, and Munzio, 1987).
- Sorbent injected into the economizer may result in fouling of the conventive heat transfer surfaces.
- Dry injection scrubbers, such as the system used at the Claremont, NH facility, do not decrease the flue gas temperature as much as wet scrubbers and dry scrubbers. Therefore, while plume buoyancy (enhanced plume dispersion) is maintained, the secondary benefit of removing condensable trace metals or organic emissions is reduced.
- With currently available sorbents, dry injection scrubbers provide lower SO_2 removal efficiencies than do wet and dry scrubbers.

Until such time as improved sorbents and processes are developed and tested on full-scale MSW combustion facilities, dry injection alone cannot be considered BACT for control of SO_2 and acid gases because of lower control efficiencies and minimal application to U.S. facilities.

3.5.2.4 Innovative Acid Gas Control Processes

The DeSONOx method is a combined catalytic procedure for the purification of flue gases, the end product being a sulfuric acid which can be used in industrial application. Nitrogen oxides, sulfur dioxides, chlorides, fluorides, remaining dusts and aerosols are precipitated. The core of the installation is the different types of series-connected converters. With ammonia added, the first converter type transforms nitrogen oxides into the harmless constituents of nitrogen and water vapor. During the next stage, which is the oxidation-type catalytic converter, sulfur dioxide (SO_2) is transformed into sulfur trioxide (SO_3) that combines with a substantial amount of steam in the flue gas to form gaseous sulfuric acid. The sulfuric acid is then condensed and washed out in the heat exchanger (cooler). Sulfuric acid aerosols posed a particular challenge. Very fine sulfuric acid droplets (aerosols) form in the transition from the gaseous state to the liquid state. These tiny droplets are deposited in wet electric filters (www.stadtwerke-muenster.de, 2004).

Although recently this technology has been marketed as a specialty technology for low SO_2 concentration flue gas streams, it has not been applied to large scale facilities. Therefore, currently, it appears that this technology must still be considered an experimental technology and has yet to be demonstrated for application to large-scale MWC facilities. Furthermore, test results have not shown acid gas control efficiencies as high as either the SDA or wet scrubber systems. Also, this technology does not appear to offer the secondary pollutant control of HCl, HF, trace metals, etc. that the SDA/FF offers. Therefore, this innovative technology will not be further considered for application to Unit 4.

3.5.3 Selection of BACT

The preceding technology evaluation identified wet scrubbers and semi-dry SDA scrubbers as the two "top" acid gas control technologies as providing the highest removal efficiencies relative to other technologies. However, because of wet scrubbers significant technical disadvantages, the wet scrubber alternative was not considered a viable means of acid gas control. The negative aspects of wet scrubbers compared to SDA systems include:

- Higher water consumption or wastewater treatment requirement resulting in increased energy and utility operating costs.
- Liquid effluent from the wet scrubber requires pretreatment to meet regulatory requirements before discharge to a municipal sewer.
- Problems associated with the disposal of wet sludge resulting from the process. Extensive sludge thickening and dewatering equipment is required.
- Corrosion, scaling and fouling of scrubber internals. Costly acid corrosion resistant construction materials are required for scrubber and downstream equipment. These materials include high nickel chromium alloys, which are extremely expensive.

- Visible steam plume under most meteorological conditions, especially during periods of high relative humidity.

- A relatively low stack gas temperature resulting in reduced buoyancy. This reduced buoyancy results in lower plume rise and poorer plume dispersion of the residual pollutants.

- It is a relatively undemonstrated control technology for modern municipal waste combustion facilities in the U.S.

Furthermore, available test data demonstrate the effectiveness of SDA/FF systems for SO_2 and acid gas emissions as well as secondary pollutant (trace organics and trace metals) control. Thus, based on the negative aspects of wet scrubbers in comparison to SDA systems, BACT for the control of SO_2 and acid gases at the proposed Unit 4 is determined to be the SDA/FF option.

Furthermore, when EPA developed the NSPS for municipal waste combustion facilities, EPA stated that the best demonstrated technology for reducing emissions of acid gases from large MWCs (i.e., greater than 250 tpd) is a SDA followed by a FF (EPA, 1989b and EPA, 1995d). The system proposed for Unit 4 is a SDA system, which is a post furnace injection technology followed by a FF baghouse. The SDA system will be designed to achieve SO_2 control levels of 26 ppmdv, corrected to 7% O_2 or 80% removal of uncontrolled emissions (geometric mean 24-hour block average), whichever is least stringent; a HCl emission limit of 25 ppmdv, corrected to 7%O_2, and SAM emission limit of 15 ppmdv, corrected to 7% O_2. The emission rates for SO_2 and acid gases are given in Section 4.

3.6 BACT Review for Particulate Matter (PM_{10}) and MWC Metals

For the purposes of this BACT review, particulate matter refers to PM_{10} and MWC metals. PM_{10} and MWC metals may be removed from the combustion gases by various types of air pollution control devices. Technologies which have been used on MWCs include fabric filters (also referred to as baghouses), ESPs and wet scrubbers. Hillsborough County proposes to use a FF system with a particulate outlet grain loading of 0.009 grains per dry standard cubic foot (gr/dscf), corrected to 7% O_2, as BACT for the emission of PM_{10} and MWC metals.

For the proposed Unit 4, there are several operations that generate particulate emissions that are controlled by FF systems. The primary source of particulate matter at the proposed Unit 4 is the combustion unit. Secondary particulate matter sources are the tipping floor area, various conveyors that will be part of the facility modification, ash handling areas and the storage and handling of lime used in the SDA and carbon used in the activated carbon injection (ACI) system. The combustion air intake for Unit 4 will collect particulate matter and odors from the tipping floor area, as is done with the existing three units. Since tipping area particulate emissions are controlled in the combustion unit and collected by the SDA/FF, these are evaluated as part of the combustion unit particulate emissions. Fugitive particulate created by the delivery and use of lime and carbon will be controlled by a separate control device mounted on each storage silo.

PM emissions from the ash handling building vent are expected to be negligible. The ash handling building is currently maintained under negative pressure and has a fabric filter mounted on top of the building to control fugitive PM emissions. The ash handling practices at the Facility limit the resuspension of ash residue. Ash residue from the furnace exit (bottom ash) and the air pollution control system (fly ash) are combined and quenched with water (15-25 percent by weight H_2O) to prevent fugitive emissions. This ash handling practice has been successfully performed for the current MWC units.

3.6.1 Emission of Particulate Matter

There are four main sources of particulate matter emissions: dust generated in the tipping hall, combustion of MSW in the furnace, particulate loadings after the SDA system, and secondary emissions from the lime and carbon silos.

The particulates generated in the pit area or tipping hall will be entrained in the air used by the combustion unit. The primary dust generating mechanisms are the movement of trucks and other equipment in the tipping area, the discharge of refuse into the pit area, the mixing and movement of refuse by the overhead cranes, the loading of refuse into hoppers, and other minor activities. The air intakes for the combustion unit are located in the tipping hall area to provide control of odors and particulate matter. Within the tipping floor area, the negative pressure created by the induced draft fans directs movement of air to the screened vents, therefore preventing odors and dust from escaping to the environment (RTP, 2003).

Particulate matter (PM) is emitted as a result of incomplete combustion of fuel as well as the entrainment of noncombustible inert matter in the flue gases. PM emissions may be solid or condensable substances. Solid PM generally consists of noncombusted inert matter, inorganic oxides, unburned combustibles and metals. A fraction of the vapor phase trace organics which were not completely converted to CO_2 and H_2O during the combustion process and the vaporized heavy metals make up the condensable portion of PM.

The size and quantity of particulates emitted from solid waste combustion depend upon such factors as flue gas residence time, underfire air velocity through the combustor system, oxidizing/reducing conditions within the furnace, temperature, flue gas mixing, boiler tube spacing, boiler configuration, flue gas velocity and the chemistry of the fuel which is burned. If the combustion takes place at higher temperatures and with the proper quantity of oxygen, the result will be more complete combustion of the fuel, and a decreased particle mass. High combustion temperatures and long residence times allow for more complete burning of organic particles with a commensurate decrease in particle size. Boiler configuration (180 degree turns) and decreased gas velocity will allow the larger, heavier particles to fall out of the flue gases as they pass the boiler, but the majority move downstream to the SDA unit. Particulates collected in the bottom ash from the boiler section are mixed in the ash discharger with fly ash particulate matter collected by the SDA system. All collected flyash is conveyed by enclosed screw conveyors.

Once the combustion exhaust gases enter the SDA, the flue gas cleaning system introduces a lime-slurry spray into the exhaust gas stream and thereby increases the particulate loading in the flue gas. As the lime-slurry dries and the water evaporates, the exhaust gases cool and the dry lime particles disperse from the resultant intense turbulence within the reaction chamber. This intense turbulence causes intimate contact between the fine lime particulate and acid gases and other constituents in the exhaust stream. Condensation onto particles and agglomeration of finer particles occurs. Some large particles in the exhaust gases are collected in the hopper of the SDA vessel. The remaining particles are carried to the FF control system where the combination of reacted and unreacted lime helps form a filter "cake" on the baghouse fabric that assists in particulate removal and ultimately, highly efficient exhaust gas cleaning (RTP, 2003).

In addition to the PM emitted from the furnace, the facility will have three secondary sources of particulate matter emissions. These sources are located at the top of the two lime (pebble and dolomite lime) and carbon silo vent(s). The lime silos are storage vessels for lime and will be used by the dry scrubbers to control SO_2 and acid gas emissions. The carbon will also be stored in a silo and will be used in the carbon injection system to control mercury emissions. Each silo will be equipped with its own fabric filter (FF) (slaker dust collector) mounted on its roof to control lime and carbon dust emissions. The FFs will be designed to discharge collected dust directly back into the storage bin.

3.6.2 Available Control Technologies

Particulate matter may be removed from the combustion gases by various types of air pollution control devices. Technologies which have been used on MWC units include FFs, electrostatic precipitators (ESP), cyclones, wet scrubbers, and others. From a top-down perspective, the most effective types of particulate matter control equipment being successfully applied to municipal waste combustors are FF and ESP systems. EPA, in its review of control technologies in support of the NSPS for municipal waste combustors, considered FF and ESP systems to be equivalent in providing control of particulate matter (EPA, 1989e; and EPA, 1995d). This equipment has been successfully applied to numerous municipal waste combustor installations in the U.S. It is a generally accepted conclusion that either an ESP or a FF system can effectively reduce the particulate loading in an exhaust gas stream from a municipal waste combustor and either technology represents the most restrictive emission control technology available for particulate emissions. The application of FF systems has been made possible primarily by the installation of acid gas scrubbers, which decrease flue gas temperature excursions to limits which are acceptable for the bag fabric. This makes the possibility of a fire due to incandescent particles igniting the fabric negligible. The trend of using baghouse rather than an ESP is due to a combination of factors. Although both of these technologies may be designed and operated to achieve the same outlet grain loading, it is proven that FF systems are better able to control the finer PM emitted, which have been proven as a source of trace heavy metal and organic emissions. Unit 4 will incorporate a FF system designed to limit particulate emissions to 0.009 grains per dry standard cubic foot (gr/dscf) of exhaust gas, corrected to 7% oxygen (O_2).

Developments in FF technology have produced a variety of filter materials including coated or non-coated fiberglass, felts, and synthetic membranes to deal with differences in ash characteristics and resistivity, inlet flue gas temperature, filter cake cohesiveness, and other problems encountered with specific FF design parameters. Hillsborough County will utilize a bag material that will meet the proposed PM_{10} emission limit of 0.009 grains per dry standard cubic foot (gr/dscf) at 7% O_2.

3.6.3 Selection of BACT

Hillsborough County is proposing to install a FF system to control particulate matter emissions which represents the "top" technology available. No further evaluation of control options is required. Therefore, a FF designed to achieve a particulate matter emission rate of 0.009 gr/dscf, controlled 7% O_2 is selected as BACT for Unit 4.

The proposed FF system will also control metal emissions from Unit 4. The proposed metal emissions limits are:

- Cadmium of 20 ug/dscm @7% O_2
- Lead of 200 ug/dscm @ 7% O_2
- MWC metals of 20.6 mg/dscm @ 7% O_2

In addition, two lime silos and one carbon silo will be added to the facility for additional lime and carbon storage needed for the Unit 4 carbon injection and SDA system. The lime and carbon silos will each be equipped with a FF unit to control particulate emissions during filling operations of each silo. The FFs for the lime and carbon silos will be designed to achieve an outlet grain loading of 0.015 gr/dscf, which is considered BACT for small, low flow FF units.

The cooling tower will use drift eliminators which will be designed to control the quantity of drift to 0.001 percent of the recirculation rate.

3.7 BACT Review for Nitrogen Oxides Emissions

NO_x is a product of all air-oxidized combustion processes, including MSW combustion. The two mechanisms that generate NO_x emissions during the combustion of MSW are thermal NO_x and fuel NO_x. Each is described in more detail in Section 3.7.1.

Generally, NO_x control technologies are based on two main principles:

- Combustion control and/or combustion process modification, and
- Post-combustion control.

Combustion control and combustion process modification technologies reduce the formation of the nitrogen oxides during the combustion processes while post-combustion/flue gas treatment technologies remove the nitrogen oxides from flue gas stream after their formation. In general, combustion controls and process modifications have been applied to a large number of MWCs. However, these NO_x control technologies have provided only modest levels of NO_x reduction. Post combustion technologies have the potential of achieving significantly greater NO_x reductions. The available post-combustion NO_x control technologies which have achieved a status of commercial applications are the Selective Catalytic Reduction (SCR) and the Selective Non-Catalytic Reduction (SNCR) flue gas treatment techniques.

Each of these NO_x control technologies are discussed in more detail in Section 3.7.2.

3.7.1 Emission of Nitrogen Oxides

The predominant form of NO_x produced during combustion is nitric oxide (NO). Nitrogen dioxide (NO_2) is also produced in lesser amounts. Upon exiting the stack essentially the entire NO formed during combustion is further oxidized to form NO_2. The resulting NO_2 is a brownish-red gas which, in the presence of sunlight and hydrocarbons, can react to form ozone (photochemical smog) and other secondary pollutants.

NO_x emissions are classified according to the source of the nitrogen from which the NO_x is formed. Nitrogen from combustion air produces "thermal NO_x," while that which originates from organically bound components in refuse produces "fuel NO_x." Though the precise mechanisms involved in converting fuel nitrogen to NO_x are not completely understood, the relative quantities of fuel NO_x and thermal NO_x produced are known to be functions of furnace design, refuse composition, and plant operating conditions.

The two major factors affecting the formation of thermal NO_x are the oxygen concentration present in the combustion zone and the flame temperature. The rate of NO_x formation has been shown to be linearly dependent on the oxygen concentration when temperature is constant. Additionally, NO_x formation tends to increase significantly with increasing temperature (at temperatures approximately above 2,100 °F) in the presence of O_2. In addition to these characteristics, NO_x formation increases linearly with increasing residence time at temperatures conducive to thermal NO_x formation (Russell and Roberts, 1984).

Fuel NO_x is formed when MSW containing nitrogen and its compounds is burned, and the nitrogen is oxidized in the process. Fuel NO_x formation is strongly affected by the local oxygen concentration present in the flame and also by the mixing rate of fuel (MSW) and combustion air. Like thermal NO_x, formation of fuel NO_x is dominated by the local combustion conditions (specifically how and at what temperature combustion air and MSW are mixed) (RTP, 2003).

3.7.2 Available Control Technologies

Emissions of NO_x from solid waste combustion can potentially be reduced by three methods: 1) reducing the solid waste nitrogen content (material separation); 2) minimizing the quantity of NO_x produced during combustion (combustion modification); and 3) reducing the quantity of NO_x in the post combustion flue gas stream (flue gas controls).

Table 3-4 is a summary of the potential NO_x control techniques which may be used at MWCs. The information also presents the current status and the projected control efficiency of each method.

Regarding source separation, while this would presumably be a means of reducing the nitrogen content of the solid waste, there is no EPA or other data which quantifies the claim that reducing the nitrogen content of the waste stream will reduce the NO_x emissions from a MWC. Thus, even tough source separation is extensively practiced in Hillsborough County (as discussed in Section 3.4), source separation is not considered a NO_x control technology and therefore will not be addressed in the BACT determination. Combustion modifications and flue gas controls for minimizing NO_x emissions were the only NO_x controlling methods evaluated. Each method was evaluated using "top down" BACT methodology. A comprehensive description and technical evaluation of each technology is presented in the following subsections.

3.7.2.1 Combustion Modifications

Combustion modification techniques can be used to reduce the conversion rate of fuel nitrogen to NO_x and suppress thermal NO_x formation as well. Three methods—staged combustion/low excess air (LEA), flue gas recirculation (FGR), and natural gas reburning-- are means to reduce NO_x emissions.

Staged Combustion/Low Excess Air (LEA)

These techniques may be used separately or together to control NO_x emissions. During staged combustion, air and fuel mixtures are combusted in two separate zones. In one zone, the fuel is fired with less than a stoichiometric amount of air thereby preventing the oxidation of fuel bound nitrogen. This creates a fuel rich local zone in regions of the primary flame. The second zone is an air rich zone where the remainder of the combustion air is introduced to complete the combustion of the fuel. The heat in the primary flame zone is not as intense as with normal firing because combustion is incomplete. The air mixed with fuel is sub-stoichiometric in the NO_x forming region of the flame, thus creating a low NO_x condition.

Similar to staged combustion, combustor operation at low excess air (LEA) reduces the oxygen available in the NO_x forming region of the flame, thereby inhibiting the formation of thermal NO_x.

LEA and staged combustion together reduce NO_x emission due to a combination of several factors. First, a lack of available oxygen for NO_x formation in the fuel rich combustion stage results in reduction of fuel-bound nitrogen to molecular nitrogen (N_2) rather than NO_x. Second, the flame temperature is generally lower in the first stage than would be expected with single stage combustion at stoichiometric conditions. Third, the peak temperature in the second stage (air rich) is lower thus reducing the generation of thermal NO_x. Thus, LEA and the staged combustion (the introduction of air at different points in the combustion system) promote reducing conditions which favor N_2 release and it also limits peak temperatures in both the primary and secondary combustion zones. This slow combustion air and fuel (MSW) mixing process assists in converting fuel bound nitrogen to molecular nitrogen rather than NO_x.

Although lower NO_x emissions can be partly attributable to a lower quantity of thermal and fuel NO_x due to lower flue gas temperatures, lower temperatures can also generate higher CO emissions and lower combustion efficiency. If this technique is not properly applied, it can result in higher emissions of CO, hydrocarbons (HC), and other products of incomplete combustion (PIC).

The formation of thermal NO_x is minimized in the Martin combustor by controlling the flame temperatures below 2,400°F (1316°C). The distribution of the combustion air is controlled with the Martin reverse reciprocating grate firing system and master combustion control system such that the available oxygen in the primary combustion zone is maintained at desired levels (RTP, 2003).

Table 3-4
Alternative Control Methods for Nitrogen Oxides

Control Method	Control Efficiency	Status
Source Separation	Not Quantifiable	Effect on MWC emissions are not quantifiable
Combustion Modification		
Good Combustion Practices (GCP), including Low Excess Air (LEA) and Staged Combustion	30-60%	Effective, but unknown side effects on combustion process and combustion related pollutants
Flue Gas Recirculation (FGR)	10-25%	Somewhat effective, but the relative moist flue gas from after the baghouse in combination with GCP may lead to increased emissions of CO and boiler problems
Gas Reburning	Unknown	Has not been applied to MWCs in the U.S.
Prism	Unknown	Has not been applied to MWCs in the U.S.
Ecotube	60% [b]	Has not been applied to MWCs in the U.S.
Water Cooled Grates	Unknown	Technology used with SNCR to reduce NO_x and NH_3 emissions ; however, they lower combustion efficiency
Flue Gas Controls		
Selective Catalytic Reduction (SCR)	50-90%	Has not been applied to MWCs in the U.S.
Selective Non-Catalytic Reduction (SNCR)	35-60%	Has been applied to MWCs in the U.S.
Wet Flue Gas Denitrification (FGD_n)	Unknown	Has not been applied to MWCs in the U.S.
Electron-Beam (E-Beam)	Unknown	Has not been applied to MWCs in the U.S.

Note: [b] Based on manufacturer quote.

In the Martin combustor approximately 60% to 70% of the combustion air is introduced below the grate to promote reducing conditions and hence conversion of fuel nitrogen to N_2. The remaining combustion air is injected at overfire air ports above the grate to complete the oxidation of combustibles. Combustion temperatures are reduced in both the primary combustion zone (the grate) by limiting the oxygen concentration and the secondary zone above the grate by the large volume of air supplied.

Flue Gas Recirculation (FGR)

In FGR, a portion of the flue gas stream is extracted and returned to the furnace. The system consists of an FGR fan assembly, air apportioning and mixing system and necessary duct work. Because the recirculated flue gas is relatively cool, the bulk furnace temperature decreases, resulting in a reduced thermal NO_x formation. FGR reduces NO_x emissions by lowering the flame temperature and reducing available oxygen. Although FGR is a technique designed to reduce thermal NO_x, the system can also help in slightly reducing fuel NO_x by a means of staging the combustion process.

Results from tests conducted at the 660-tpd Volund refractory wall furnace at the Kita refuse combustion facility in Japan indicated that 10 to 25 percent NO_x emission reductions were achievable (Radian, 1989). This level of NO_x emission reduction was achieved by recirculating an amount of flue gas equivalent to 20 percent of the combustion air.

Based on FGR's relatively low levels of NO_x reduction, MWC suppliers in the past were reluctant to incorporate FGR into their furnace designs. However, within the last 5 years MWC suppliers and operating companies have realized the benefit of FGR, particularly in combination with other NO_x control technologies. In fact, two of the major MWC suppliers (Martin and Von Roll) now include FGR as part of their standard combustion system offering. The benefit of FGR, particularly in combination with SNCR, is that it reduces the baseline NO_x level and it reduces ammonia use. Since FGR has proven to be effective in combination with other NO_x control technologies and is now part of the standard MWC offering, FGR will be considered in combination with SNCR and SCR as NO_x control technologies.

Natural Gas Reburning

Gas reburning is a NO_x control technique that overlaps combustion modification techniques. LEA is provided in the combustor, with recirculated flue gas introduced above the grate. Natural gas is added to this LEA zone to generate a fuel-rich zone. Air is supplied above the fuel-rich zone to complete combustion. This process is designed to reduce NO_x formation without increasing CO emissions.

A program was initiated to evaluate the potential for reducing air pollutant emissions from MSW combustion systems using natural gas reburning. The program was conducted jointly by the Institute of Gas Technology, the Gas Research Institute, Riley Stoker Corporation and Takuma Company Ltd.

Three major tasks were included in the program: (1) acquisition of baseline data from a commercial operating facility, (2) pilot-scale development and testing of the reburning technology, and (3) field demonstration testing of the technology. The gas reburning concept being evaluated for MSW combustion is similar to the reburning technique being investigated to reduce NO_x emissions from fossil fuel combustion systems. Natural gas is introduced above the main combustion zone to create a reducing environment where significant amounts of NO_x and other fixed nitrogen species (NH_i, HCN), generated in the main combustion zone, are reduced to molecular N_2.

Results of the pilot scale testing demonstrated up to 70 percent reduction in NO_x emissions using gas reburning. The effects of gas injection location, reburning zone stoichiometry and residence time, overall boiler excess air and the amount of natural gas reburning on NO_x emissions are characterized. The impact of gas reburning on reducing other emissions such as CO, unburned THC and dioxin is also possible (Abbasi, et al, 1989).

Additional tests with natural gas reburning were conducted at the Olmsted County (Minnesota) municipal waste combustion facility by a joint program with the Gas Research Institute (Abbasi, et al., 1991). The test data showed that the natural gas injection of 12 percent to 15 percent (heat input basis) and FGR of 6 percent to 8 percent resulted in NO_x reduction of 60 percent and CO reduction of 50 percent. Natural gas reburning also allowed a reduction of excess air from 80 percent to 40 percent which provided increased boiler efficiency. The test data also indicated that optimization of residence time in the combustor is important for simultaneous reduction of NO_x and CO. However, long-term operational data on natural gas reburning in MWCs is not available (RTP, 2003).

Natural gas reburning has primarily been applied to fossil fuel boilers as a retrofit NO_x control technique or for seasonal NO_x reductions, and has not been used as a NO_x control method on large-scale MWCs. Although this technology has been applied to fossil-fuel combustion, it is not considered BACT for MSW combustion because of the increased natural gas costs and operational costs compared to less expensive, yet equally effective NO_x reduction techniques.

Ecotube

Ecotube is a recently developed staged combustion process offered by Synterprise. Ecotube essentially consists of one or more retractable rotating lances (3 to 7 meters long) located just above the primary combustion zone. The lances are designed to inject high velocity air, ammonia or urea through nozzles into the upper combustion zone of the furnace. Synterprise claims that Ecotube can: reduce NO_x by 60% or more, reduce CO and VOC emissions, improve mixing of the overfire air in a MWC, lower overall excess air levels by allowing the lower furnace to operate at near stoichiometric conditions, and improve boiler efficiency, due to the smaller amount of flue gas. To support these claims, Synterprise has offered limited data from a retrofit Ecotube installation on a MWC in Coventry, England.

Emissions data from the Coventry installation has the following characteristics:

> NOx: range of 140 to 280 ppmdv at 7% O_2 with an estimated average of 210 ppmdv at 7% O_2
>
> CO: average of approximately 25 ppmdv at 7% O_2 with spikes of 400 ppmdv at 7% O_2 occurring every couple of hours

Since it is not known what the uncontrolled NOx level was, the percent of NO_x reduction can not be determined. In any case, an average outlet NO_x level of 210 ppdv is rather unimpressive as a controlled NO_x emission level. The CO data with spikes of 400 ppmdv suggest an unstable combustion process, which could be in violation of the EPA MWC performance standard for CO (100 ppmdv of CO at 7% O_2, 4-hour block average).

Regarding the overall practicality of the system, there is serious question as to how the rotating lances would survive in the combustion zone of the furnace. The lances would be subject to metal fatigue, corrosion, plugging and slag formation. Furthermore, when the lances are retracted for repair or routine maintenance, emission characteristics as well as control of overfire air would significantly deteriorate.

In conclusion, there is too little data available and not enough operating experience with Ecotube to judge whether it has any significant advantage over current MWC systems which use high velocity overfire air ports to stage combustion and introduce secondary combustion air. Due to the limited data and operating experience with Ecotube, it will not be considered further as a NO_x BACT.

Prism

Prism is a combustion process modification offered by Seghers which consists of a prism shaped, water-cooled structure located just above the grate of a MWC. The flue gas flow off the grate is divided into two streams which flow on either side of the prism structure. Secondary air is injected into the two gas streams from the four corners of the combustor. The benefit of prism appears to be that, due to the prism structure, the secondary air needs to penetrate only ¼ of the furnace depth and hence better mixing of secondary air is achieved. Based on performance data taken from the AZN Moerdijk facility, Prism provides more uniform flue gas temperature and oxygen distributions across the furnace and lower maximum temperatures at the furnace outlet. When used in combination with SNCR, Prism's main benefit is lower ammonia consumption.

In summary, Prism is a rather substantial configuration change to the standard MWC grate technology. While it appears to improve the temperature and oxygen distributions within the combustor, its overall impact on NO_x control is limited and it appears that other less costly furnace modifications such as FGR can accomplish similar results. Due to the limited operating data and experience with Prism and relatively small (if any) improvement on reducing NO_x emissions, Prism will not be further considered as a NO_x BACT.

Water Cooled (WC) Grates
Another means of reducing combustion zone temperatures and thereby reduce NO_x emissions is to use WC grates. This technology has been used for a number of years and both Martin and Von Roll can offer a MWC with WC grates. The drawback of WC grates is that they lower combustion efficiency; however, the grates should last longer. When used in combination with SNCR, WC grates reportedly reduce baseline NO_x emissions and reduce ammonia usage. While one might assume that the use of WC grates and FGR with SNCR would further reduce NO_x emissions, there is no data to support the theory that the beneficial effect of WC grates and FGR are additive. In fact it may be that with so many combustion process parameters to control, it may be difficult or impossible to optimize any of them. In conclusion, WC grates is judged to be another means of enhancing SNCR but does not appear to offer any improvement over FGR either singularly or in combination with FGR. Based on the above, WC grates will not be further considered as a NOx control technology.

3.7.2.2 Flue Gas Controls

Flue gas controls can generally be placed into one of two categories: SCR and SNCR. These two processes are both based on selective reduction of NO_x present in flue gas. A chemical reagent is injected into flue gas stream selectively reducing nitrogen oxides into molecular nitrogen, N_2, more stable form of nitrogen in the atmosphere, and water. A metal-based catalyst is employed in the SCR process. A relatively high NO_x removal efficiency of about 50 to 90 percent can be obtained by the SCR process while the SNCR is capable of reducing NO_x with efficiency ranging from 35 up to 60 percent.

The flue gas from MSW combustion contains high concentrations of dusts and acid compounds that cause the catalyst damage. Therefore, these pollutants should be removed from the flue gas prior to treatment in the SCR unit. For this reason, SCR units are usually installed after acid gas and dust removal units, where the flue gas temperatures are lower. Because the SCR process requires the flue gas temperature of 300-400°C (572-752°F), flue gas must be pre-heated. It implies high installation and operation costs, which limits the SCR application on MWC facilities despite its high NO_x removal efficiency. Therefore, there have been more SNCR systems used due to its simplicity of installation and low installation costs.

Three additional technologies, flue gas denitrification (FGD_n), the electron-beam (E-Beam) process, and other catalytic methods such as SCONOX® have been tested or applied for NO_x control on industrial facilities and are also discussed below.

The following discussion explains the technological aspects of each of these control methods and their associated environmental, energy and economic impacts.

Selective Catalytic Reduction (SCR)
The SCR process reduces NO to water and elemental nitrogen by injecting aqueous NH_3 into the flue gas through a catalyst bed. The function of the catalyst is to effectively lower the activation energy of the NO in its decomposition reaction to N_2.

This lower energy allows the reaction to proceed in a lower and broader temperature range than would otherwise be possible. The reactions between NO_x and NH_3 occur at temperatures of 375-750°F (191-399°C), depending on the specific catalyst and the type and level of competing contaminants in the flue gas. Lower temperatures yield slow reaction rates and higher temperatures result in shortened catalyst life.

Application of SCR technology to MWCs is difficult mainly due to the acid gas content and relatively high particulate grain loading of the flue gas. These flue gas components erode the catalyst and substrate material as well as poison the catalyst rendering the bed ineffective for NO_x removal. If these problems are to be avoided, then the SCR reactor must be located downstream of the air pollution control equipment and would have significant economic disadvantages since it would require reheating of the flue gas prior to entering the bed (Radian, 1989).

SCR has been successfully applied at coal, oil, and natural gas-fired facilities in the U.S. Reductions of NO_x emissions have ranged from 50 to 90 percent and have been measured at these facilities. There are no applications of SCR on municipal waste combustion facilities in the U.S. SCR systems have been applied and are operating on municipal waste combustion facilities in Europe and Asia, and most recently in Canada. Therefore, there are technical and cost data available for these international facilities.

Hillsborough County attempted to obtain information from foreign facilities regarding continuous operation of the SCR units and their long-term emission reduction capabilities. An intensive search for information was initiated, with requests for information submitted to a number of catalyst manufacturers, catalyst system suppliers, and individual facilities. The focus of the information request was to obtain a list of MWCs employing SCR as well as obtain information on system operation. It was considered necessary to have this information in order to perform proper feasibility analyses as required by EPA. Very limited data was received from European facilities and SCR system suppliers.

Table 3-5 provides a sample list of European municipal waste combustion facilities utilizing SCR. **Table 3-6** provides NO_x outlet emissions information received from a number of European facilities. The data provided consisted only of outlet emissions data. As shown, control efficiencies were not reported as well as averaging times and emissions compliance testing procedures. Although relatively low outlet NO_x concentrations are reported, it is difficult to determine the true applicability of these levels relative to the requirement to guarantee a continuous emission level tied to a short-term averaging period as required of U.S. MWCs. In addition there is no indication of the variability of the NO_x emissions.

Table 3-5
Sample List of European Municipal Waste Combustion Facilities Utilizing SCR and Their Air Pollution Control Equipment Configuration [a,b]

Municipal Waste Combustion Facility Name	Location	Air Pollution Control Equipment Configuration
MVA Spittelau	Vienna, Austria	ESP, Two Stage Scrubber using lime and caustic, EDV, SCR
AVR Rotterdam	Rotterdam City, The Netherlands	ESP, Two Scrubbers, Fixed Carbon Filter, SCR
SITA ReEnergy	Roosendaal, The Netherlands	ESP, Gas Suspension Absorber (lime injection), ACI, FF, SCR
COMMUNAUTE URBAINE DE LILLE	Lillie, France	ESP, SDA with Rotary Atomizer, FF, Wet Scrubber, SCR
U.V.E. SMEDAR (SICDOM)	Rouen, France	ESP, SDA with Rotary Atomizer, FF, SCR
RMHKW Boblingen	Boblingen, Germany	FF, 2-Stage HCl Scrubber, 1-Stage SO2 Scrubber, ACR, SCR
IVAGO	Ghent, Belgium	ESP, SDA with Rotary Atomizer, FF, SCR
MVA Koln	Koln, Germany	Spray Dryer, FF, 1-Stage Prescrubber, 1-Stage SO2 Scrubber, SCR, ACR
AEZ Kreis Wesel	Wesel, Germany	Spray Dryer, ESP, 1-Stage Prescrubber, 1-Stage SO_2 Scrubber, SCR, ACR
GML	Ludwigshafen, Germany	SDA with Diffusers, ESP, WS, SCR
AVI TWENTE b.v.	Twente, The Netherlands	ESP, SDA with Rotary Atomizer, ESP, WS, Filsorption, SCR

Note: ESP = Electrostatic Precipitator, EDV = Electrodynamic Venturi, SCR = Selective Catalytic Reduction, ACI = Activated Carbon Injection, ACR= Activated Carbon Reactor, FF = Fabric Filter Baghouse, SDA = Spray Dry Absorber WS = Wet Scrubber

Source: [a] RTP Environmental Associates, Inc. 2003. Lee County Energy Recovery Facility, Lee County Solid Waste Division, Lee County, Florida. Prevention of Significant Deterioration Air Permit Application Major Modification to Add a Third Municipal Waste Combustor Unit to the Existing Lee County Energy Recovery Facility. February 2003.

Table 3-6
European Municipal Waste Combustion Facility with SCR Emissions Information Received During the BACT Preparation Process[a]

Municipal Waste Combustion (Location)	NO_x Emissions (ppmdv)[b]	Averaging Time of Reported Emissions	Testing Procedures Information
MVA Spittelau (Vienna, Austria)	0 to 64	Not Specified	Not Specified
AVR (Rotterdam, The Netherlands)	37	24-hour avg. [c]	Not Specified
SITA ReEnergy (Formerly Heeren) (Roosendaal, The Netherlands)[d]	26-31	Three 1-hour tests	Not Specified
SITA ReEnergy (Roosendaal, The Netherlands)[e]	39,35,42[f]	Not Specified	Not Specified
German Municipal Waste Combustion Facilities	19-37	Not Specified	Not Specified
MHKW (Kassel, Germany)	52	Not Specified	Not Specified
Gavi Wijster (The Netherlands)	52	Not Specified	Not Specified
Renova (Gothenburg, Sweden)	45-52	Not Specified	Not Specified
IVAGO (Ghent, Belgium)	51	Not Specified	Not Specified
(Hagen, Germany)	90	Not Specified	Not Specified
MV Huisvuilcentrale N-H (Alkmaar, The Netherlands)	41	Not Specified	Not Specified

Sources: [a] RTP Environmental Associates, Inc. 2003. Lee County Energy Recovery Facility, Lee County Solid Waste Division, Lee County, Florida. Prevention of Significant Deterioration Air Permit Application Major Modification to Add a Third Municipal Waste Combustor Unit to the Existing Lee County Energy Recovery Facility. February 2003.
[b] Reported NO_x emissions are corrected to 7% O_2 at 20C and 1 Atmosphere.
[c] Average based on reported 1-hour average values over a two-week period.
[d] Reference: CRI Catalyst Co. UK Ltd., 1997.
[e] Reference: Heath, S., 2001c.
[f] First value from year 1998, second value from year 1999, third value from year 2000 (No other information provided).

Selective Non-Catalytic Reduction (SNCR)

SNCR also called Thermal $DeNO_x$, is a flue gas treatment technology for NO_x control that involves the injection of an amine-based compound into the flue gas stream at an appropriate temperature range for the reduction of NO_x. An amine-based compound, such as ammonia, NH_3, or urea, $(NH_2)_2CO$, is used as a nitrogen oxides reducing agent for the SNCR processes. Either anhydrous or aqueous ammonia can be used. When ammonia or urea is injected into the flue gas stream at an appropriate temperature window, it selectively reduces the NO_x into molecular nitrogen, N_2, and water, H_2O. At stoichiometric conditions, when the adequate residence time is reached, the overall reactions that occur may be written as:

Anhydrous Ammonia

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

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Aqueous Ammonia (Urea)

$$2(NH_2)_2CO + 4NO + O_2 \rightarrow 4N_2 + 2CO_2 + 4H_2O$$

Generally, the appropriate temperature window of flue gas that is necessary for the desirable chemical reactions between the nitrogen oxides and the injected ammonia or urea is determined to be approximately 800° to 1050°C (1472°-1922°F). However, these reactions are very sensitive to temperature and dominate at the flue gas temperature range of 800° - 1000°C (1472°-1832°F) (R. Gavasci, et al, 1999).

Since oxygen is present in the flue gas, a portion of the ammonia is oxidized too. The reaction of ammonia oxidation at temperatures greater than 1100°C (2012°F) can be expressed as below:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$$

At the flue gas temperature above 1100°C (2012°F) the reaction of ammonia oxidation becomes predominant which is undesirable. Nitrogen monoxide, NO, is formed as a product of this reaction of ammonia oxidation. As a result, when the flue gas temperature at reagent injection locations is higher than the appropriate temperature window the SNCR process results in NO_x formation rather than NO_x reduction (R. Gavasci, et al, 1999).

The peak or the optimum NO_x reduction takes place in a very narrow temperature range of 927° to 1028°C (1701°-1882°F). This relatively high reaction temperature required for the process can be achieved by injecting the chemical reagent into the flue gas stream directly after the post-combustion chamber or at the inlet of the boiler where the flue gas temperature is more or less within the appropriate range. By injecting a readily oxidizable gas, such as hydrogen, H_2, with the ammonia, NH_3, the required temperature window for NO_x reduction can be lowered to approximately 740°C to 760°C (1364°-1400°F) (R. Gavasci, et al, 1999).

At temperatures lower than the required temperature window the NO_x reduction reaction rates become lower, and unreacted ammonia may slip through and be emitted from the stack. This phenomenon, commonly called "ammonia-slip", is unacceptable above certain limits because ammonia is considered an air pollutant and is odorous at very low concentrations. In full scale applications it is very difficult to maintain the flue gas temperature at chemical reagent injection locations within the temperature window required for the SNCR process (R. Gavasci, et al, 1999).

As discussed above, the SNCR process commonly uses injection of anhydrous or aqueous ammonia. A urea injection technique developed by Fuel-Tech. Inc. (NOxOUT technology) has been applied to control combustion NO_x emissions. Both ammonia and urea processes have been demonstrated on municipal waste combustion facilities in the U.S. Since both ammonia injection and urea injection are the most widely used, both technologies are further discussed. The only difference between these reagents is the physical form of the reagent. Anhydrous ammonia requires vaporizers to convert the compressed, liquid ammonia into a gaseous vapor. Aqueous ammonia is stored in a liquid form at an ammonia concentration of approximately 20-29 percent by weight. To avoid the safety and regulatory issues associated with anhydrous ammonia, the usage of aqueous ammonia has been adopted at numerous facilities including the existing Facility Units 1, 2 and 3. The existing Facility Units 1, 2 and 3 use aqueous ammonia-based SNCR and have consistently achieved permitted NO_x emission levels throughout the operational history of the units. **Table 3-7** presents the NOx permit emission limits and annual averages.

Table 3-7
Existing MWC Units NO_x Permit Limits and Equivalent Annual Average Emission Rates

MWC Units	NO_x Permit Limit [a] (ppmv, corrected to 7% O_2)	3-Year Average NO_x Concentration [b] (ppmv, corrected to 7% O_2)
Unit 1	205	190.0
Unit 2	205	188.7
Unit 3	205	189.0

Note: [a] Permit limit is based on a 24-hour daily arithmetic mean.
[b] Based on three years of stack test data for the existing MWC units.

One advantage of aqueous ammonia over anhydrous ammonia is that aqueous ammonia can be more readily and more completely mixed in the flue gas stream and hence achieve higher NOx removal efficiencies at lower ammonia slip levels than gaseous ammonia injection systems.

Although SNCR technology has been successfully applied to modern MWC facilities, the technology presents several environmental and technical disadvantages. These disadvantages include:

- Residual NH_3 may react with acid gases in the boiler to form by-product ammonium salts. Two of the salts formed, ammonium sulfate and ammonium bisulfate, could potentially cause fouling and corrosion problems in the boiler particularly at the rear section of the boiler, the economizer.
- The presence of CO above approximately 100 ppmv adversely effects the SNCR chemistry. The detrimental effect of CO is due to the fact that both reactions (namely, the oxidation of CO and the reduction of NO_x) require and compete for the same OH radicals to proceed. The presence of CO in the combustion gases causes a shift and reduction in the effective NO_x/NH_3 temperature reaction range (EPA, 1989c).
- Residual ammonia emissions are emitted as a result of the SNCR process.

Fuel Tech's NOxOUT uses urea, instead of ammonia. The urea is fed to the boiler as a 50 percent by-weight solution cut with water to maintain the required volumetric flow rate to give adequate distribution across the boiler. NO_x control is affected using essentially the same net chemistry as Thermal $DeNO_x$. The overall reaction between urea and NO can be expressed as follows:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + 2H_2O + CO_2$$

The reaction takes place in a temperature range similar to that for Thermal $DeNO_x$ and the lower temperature limit can also be expanded to 700° C (1300° F) with the use of a proprietary urea additive.

The Fuel-Tech NOxOUT process has been installed and demonstrated on a number of utility and industrial boilers in North America and Europe, as well as several MWCs. The NO_x reductions achieved at U.S. facilities have ranged similarly to the ammonia based SNCR process. The NOxOUT process has also been used in full-scale European municipal waste combustion facilities at Frankfurt, Germany, and Switzerland (RTP, 2003). Proponents of NOxOUT claim that a urea based reagent can achieve NO_x removal as high as or higher than ammonia based reagents at lower ammonia slip levels.

Hillsborough County is proposing to install SNCR utilizing direct injection of aqueous ammonia in combination with FGR at the Unit 4 combustor to meet an outlet emission level of 110 ppmdv corrected to 7% O_2 averaged over a 12-month period and 150 ppmdv corrected to 7% O_2 averaged over a 24-hour period. These NOx emission limits are based on the experience acquired by Covanta from operation of the SNCR systems at the Facility and other MWC facilities. It is noted that the existing units at the Facility averaged 190 ppmdv over a 3 year period. Thus, the proposed SNCR system for the 4th MWC will have to operate at a significantly greater NOx removal efficiency. Achieving 110 ppmdv will require 59% control of NOx which on a continuous basis is at the limit of SNCR control capability.

Wet Flue Gas Denitrification (FGD$_n$)

FGD$_n$ systems may be divided into at least four major process systems: 1) oxidation-absorption-reduction (OAR), 2) oxidation-absorption, 3) absorption-reduction, 4) absorption-oxidation. Of these four types, OAR is somewhat more advanced because it is a derivative of already established FGD systems.

OAR operates by injecting oxidizing agents, such as ozone into the flue gas upstream of wet scrubbers (CARB, 1984). The relatively insoluble NO oxidizes to the more soluble NO_2 which, when in solution, reduces to N_2 by consuming some of the absorbed SO_2. It is possible to modify conventional flue gas desulfurization systems that use water soluble SO_2 absorbents by adding oxidizing agents which circulate with the scrubber fluid. Simultaneous NO_x and SO_2 removal efficiencies as high as 90 percent may be achieved (CARB, 1984). Such modified flue gas desulfurization systems may be applicable to refuse-fired boilers (Beaumont, 1986).

Absorption-oxidation processes are not as developed as the other previously described wet NO_x control systems. Results from pilot-scale facilities indicate high NO_x removal efficiencies are achievable, but suggest that the system faces undesirable operational problems (CARB, 1984).

Supplier information was researched from several corporations specializing in pollution control technology with specific experience with wet FGD$_n$ systems. Tri-Mer Corporation attests to having approximately 50 installations currently operating throughout the U.S. The Tri-Mer TRI-NO_x technology is proprietary but appears to be a type of absorption-reduction system with oxidation steps, if necessary. Tri-Mer's technology has not been applied to flue gas from a municipal solid waste combustion facility. Tri-Mer Corporation has specialized in controlling emissions from the chemical and metal finishing industries and normally designs systems to handle flue gas flow rates of between 20 and 20,000 scfm. These flow rates are at best an order of magnitude lower than the flue gas flow rate of Unit 4. Also, the industrial flue gases described normally contains substantially higher concentrations of NO_x than is found in the flue gas of municipal waste combustion facilities (RTP, 2003).

Disadvantages of these systems stem from the cost of oxidizing agents, wastewater treatment associated with wet scrubber effluent, and flue gas reheat requirements. The wet FGD$_n$ processes have not been demonstrated on a wide-scale to be technically reliable nor economically sound, and therefore cannot be considered BACT.

Electron Beam

E- beam FGT process is very versatile and an effective process to remove SO_2 and NO_x from of the flue gas produced in the combustion of fossil fuel. This process is a dry process using electron beam irradiation in the presence of ammonia (NH_3) to initiate chemical conversion of nitrogen oxides into an aerosol which can be easily collected by conventional methods using an electrostatic precipitators or bag house filters (Turhan, et al, 2004).

The flue gas flows into the process vessel then gas mixture is subjected to an intense field of energized electrons, which collide with the flue gas molecules resulting in molecular ionization. These ions interact with flue gas constituents resulting in the creation of free atoms and radical species such as O, OH, N and HO_2. These are capable of rapid reaction with NO_x and water in the flue gas to ultimately yield a mixture of fine mist and vapor of nitric acids (HNO_3). In the presence of NH_3, these acids are converted to ammonium nitrate (NH_4NO_3). These salts are recovered as a dry powder using a conventional particle collector. The collected powder is potentially salable as an agricultural fertilizer. Other organic compounds such as VOCs can also be treated using the same principle (Turhan, et al, 2004).

The potential of using radiation to initiate the process aimed at removal of SO_2 and NOx from combustion flue gas, in order to prevent environmental pollution, was recognized in the early 1970s in Japan. The success of the initial tests indicated a future potential use for the electron beam process. Although this technology has been installed in cleaning flue gas from fossil fuel combustion, there have been no tests or demonstrations on modern MWC units (Turhan, et al, 2004).

The E-Beam process, though not technically infeasible, is an undemonstrated technology for NO_x control on large scale, modern MWCs that is not expected to remove NO_x as efficiently as either SCR or SNCR. It is also expected that costs for this system would be substantially higher than other proven NO_x control technologies in the industry. Therefore, this technology cannot be considered BACT and will not be evaluated further.

Innovative NOx Control Methods

Emerichem, LLC (formerly Goalline Environmental Technologies) markets the SCONOX® pollution control technology. SCONOX® is a catalytic control method for NOx that does not utilize ammonia (or urea) as a reagent. SCONOX® has been applied to clean-fuel fired combustion equipment, such as natural gas-fired boilers and turbines, and has demonstrated high NO_x removal efficiencies. SCONOX® has not been tested or applied to a large-scale MWC for NO_x control and is not currently marketed in this application. Furthermore, a representative of Emerichem stated that the company would decline from offering to provide SCONOX® in this application due to the potential for catalyst fouling and deactivation from trace materials in the flue gases. (Hober, M., 2002a) Hence, this innovative technology must be considered technically infeasible at this time for application to Unit 4.

3.7.3 Ranking of Alternative Control Technologies

Due to technical problems and system non-availability associated with wet FGD_n, the E-Beam process, and the SCONOX® process; these technologies will not be evaluated with FGR further. Relative to NOx control, the "top" control method to be evaluated is SCR with FGR with a stack NO_x emission limit of 70 ppmdv. SNCR with FGR with a stack NO_x emission limit of 110 ppmdv is considered the second most effective option relative to SCR.

A key parameter in the BACT analysis is the selection of the SCR stack emission limit. Some of the SCR system suppliers offered a NO_x emission limit of 50 ppmdv or lower. However, it must be taken into consideration that a vendor is only responsible for achieving an emission guarantee during a relatively short performance test conducted under very controlled and stable conditions. Since NO_x is a combustion parameter, its rate of formation is very sensitive to changes in combustion conditions, namely: local temperatures and oxygen concentrations and fuel characteristics, all of which exhibit significant variations in a MWC. Inspection of a typical NOx emission monitor strip chart from the IVAGO MWC in Ghent, Belgium shows that NO_x concentrations continuously fluctuated between 35 to 70 ppm during each hour of operation. Given the significant fluctuation in SCR controlled NO_x emissions and the fact that the SCR emission limit must be achieved continuously on a year in year out basis, it is reasonable and prudent to apply a safety factor to the vendor's "guaranteed" NO_x emission limit. One approach is to set the NO_x emission limit at the NOx permit limit in a country where SCR systems on MWCs have been in practice for many years. The Austrian NO_x permit limit for MWCs is one of the lowest in Europe and is equivalent to 70 ppmdv corrected to 7% oxygen. This limit was selected as the NOx SCR emission limit for this BACT evaluation.

3.7.4 Environmental Impact

The beneficial environmental impacts of SNCR and SCR are the removal of significant quantities of NO_x from the atmosphere. SNCR will remove 324 tons of NO_x per year and SCR will remove 405 tons of NO_x per year. Neither SNCR nor SCR produces a continuous side stream which requires treatment. Both urea and aqueous ammonia are subject to SARA (Superfund Amendments and Reauthorization Act), Title III reporting as hazardous substances, and there are risks associated with the shipping, handling and storage of these chemicals. However, both chemicals are significantly safer to store and use than anhydrous ammonia.

One of the possible detrimental effects of both SNCR and SCR is the possible formation of a visible plume. A visible plume can result from the reaction of any excess ammonia and any remaining chlorides in the flue gas to form ammonium chloride. Visible plumes have been observed at some MWCs with SNCR when ammonia injection rates were raised to high levels. However, both processes would be designed using sophisticated fluid dynamic models to optimize the chemical reaction kinetics and the placement of the ammonia injectors. Real time computer control systems would be continuously monitoring process temperatures and outlet NO_x and ammonia levels to control the feed rate of ammonia and minimize its use. Also the spray dry absorber and fabric filter (SDA and FF) will achieve 95% control of HCl resulting in HCl emissions of less than 25 ppmdv. Thus, state-of the-art control systems and low HCl concentrations in the flue gas will minimize the chance of a visible plume.

The only significant environmental impact of SCR would be the disposal of approximately 3,000 to 4,000 pounds of spent catalyst per year. Since the catalyst life is estimated at 3 years, the quantity of spent catalyst is estimated at 1/3 rd of the catalyst initially provided by the SCR supplier. The spent catalyst would most likely have to be disposed of as hazardous waste.

3.7.5 Economic Impact

The determination of the economic impact of the various control technologies involves an assessment of capital and annual operations and maintenance (O&M) costs. For the SCR alternative the economic assessment was hampered for the following reasons:

1. There are no operating SCR systems on MWCs in the USA from which to obtain operating and cost data.

2. The proposals and operating data provided by SCR vendors were limited and incomplete.

3. Efforts to contact European SCR installations to obtain performance and cost data yielded limited useful information.

It is noteworthy that all of the SCR vendors contacted only proposed using a "cold side" SCR system downstream of the SDA and FF which would remove particulate matter, metals and acid gases. The use of a "hot side" SCR system would expose the catalyst to severe plugging from particulate and to potential catalyst poisons such as sodium, potassium, calcium, chlorine, fluorine, arsenic, lead and phosphates. A "hot side" SCR system would also convert some of the SO_2 to SO_3 which would then react with the ammonia to form ammonium sulfate and ammonium bisulfate. Both of these ammonium salts form sticky deposits that can plug up the catalyst and downstream duct passageways. Therefore, only a "cold side" SCR system was evaluated.

In developing the capital and O&M cost estimates, standardized methods presented in USEPA OAQPS Air Pollution Control Manual were used (USEPA, OAQPS, 2002). Although the most recent edition of this manual (dated January 2002) contains a chapter on NO_x control using SCR, the procedures developed are for a "hot side" SCR system on a coal fired boiler and thus are not suitable for a "cold side" SCR system on a MWC. Therefore the cost procedures in the latest edition of this manual were not used.

In order to prepare the economic analysis, budgetary quotations on a "cold side" SCR system were solicited from a number of SCR catalyst manufactures and SCR system suppliers. In addition to the capital cost, design, operating and performance data were requested. Specifically, the following data were requested: catalyst composition and minimum temperature required to achieve stated NOx reduction, catalyst volume, expected catalyst life, guaranteed NO_x emission limit, ammonia slip level, dimensions of SCR system, utility and chemical requirements (natural gas, power, ammonia), estimated O&M labor, estimated maintenance materials cost and SCR vendor's scope of supply.

A "cold side" SCR system would consist of the following components:

- Flue gas inlet and outlet ductwork
- Flue gas to flue gas heat exchanger
- Steam coil heat exchanger
- In line duct burner
- Aqueous ammonia storage tanks and feed pumps
- Aqueous ammonia evaporator and evaporator blower
- Gaseous ammonia injection grid and piping
- Interconnecting ductwork between heat exchangers, ammonia injection grid and catalyst bed
- Ammonia to flue gas static mixers
- Catalyst and catalyst housing
- Catalyst handling system: hoists, monorail and loading carts
- Structural steel including all stairs, platforms, railing and ladders
- NOx analyzer
- Instrumentation and controls

Solicitations for capital and O&M costs were sent to the following SCR vendors:

- Riley Power, a Babcock Power Inc. Company
- Seghers/Keppel
- BD Heat Recovery Division Inc./Haldor Topsoe
- Argillon (formerly Siemens)
- KWH
- Cormetech
- Foster Wheeler

- Alstom Power
- CRI Catalyst Company
- Mobotec

Some of the vendors are strictly catalyst manufacturers who were not able to provide a complete system cost. Three of the vendors (Riley Power, Seghers/Keppel and BD Heat) provided complete system costs. Argillon stated that they did not wish to propose an SCR system for a MWC application. Two of the vendors (KWH and Cormetech) did not respond to our inquiries. Foster Wheeler (FW) said that they have no direct experience with waste incineration type SCR systems, but they have designed many SCR systems for other type fuels. FW said they could provide an SCR proposal for Hillsborough on a "reimbursable basis with the agreement that FW would be awarded the work in the event the project moves ahead". Alstom provided some process and performance data on their SCR system and an 'indicative estimate" of the capital cost which did not include provision for heating the flue gas to the temperature required for their SCR system (525°F). CRI Catalyst provided a cost proposal but it also did not include any provision for heating the cold flue gas to the temperature required by the SCR system. Hence Alstom's and CRI Catalyst's proposals were of limited value.

Mobotec was very interested in supplying their ROFA/ROTAMIX technology which essentially was an enhanced flue gas recirculation combined with SNCR. Mobotec's system consisted of using a high pressure blower to recirculate flue gas from the outlet of the boiler back to the inlet of the boiler above the combustion zone. Ammonia would be injected into the turbulent zone created by the recirculated flue gas. Mobotec claimed that by using Computational Fluid Dynamics (CFD) this technology could achieve low NO_x emission levels. The Mobotec representative stated that based on an inlet NOx concentration of 270 ppmdv an outlet NO_x level of 110 to 130 ppmdv could be expected. Since the Mobotec system could not provide a lower outlet NO_x concentration than what Covanta was willing to guarantee with SNCR and FGR, the Mobotec system was not further evaluated.

BD Heat provided a substantial cost proposal with accompanying process data. The BD Heat proposal contained an all carbon steel flue gas to flue gas heat exchanger. We have significant concerns regarding its reliability and durability, particularly in a waste incineration flue gas stream, albeit downstream of the SDA and FF. We do not know if the BD Heat SCR system with all carbon steel heat exchanger has been successfully used on a MWC. The overall dimensions of the BD Heat SCR system were 43 ft by 31 ft by 60 ft in height. Interestingly, BD Heat proposed a catalyst operating temperature of 650°F versus approximately 500°F to 540°F proposed by other SCR suppliers. Since the BD Heat capital cost was not consistent with the two other cost proposals presented below, it was not used in the economic analysis.

Seghers/Keppel provided process data, technical papers and brochure on their SCR process and an uninstalled budgetary cost estimate for a complete "cold end" SCR system of $5,900,000. Riley Power, a Babcock Power Company, provided a well documented, uninstalled budgetary estimate of $6,500,000. Based on Babcock Power's impressive number of SCR installations and their successful track record with SCR systems on MWCs, their uninstalled cost estimate was used as the basis of the economic analysis.

The economic analysis of SCR with FGR for the 4th MWC at Hillsborough is presented in **Table 3-8**. Installed costs and indirect costs are based on cost factors from similarly complex APC systems from the OAQPS Manual. Note that the installation costs had to take into consideration the fact that the Hillsborough WTE plant site is very congested and has limited space available for the SCR system for the 4th MWC. The original Hillsborough WTE plant was designed with just electrostatic precipitators (ESPs) for APC systems. When the plant was upgraded to SDA and FF approximately 5 to 6 years ago, the ESPs at the end of each MWC train had to be demolished and the new SDA and FF installed. To keep the plant in operation, the SDA and FF for unit 1 were located in the space were the ESP for unit 2 was located. Likewise the SDA and FF for unit 2 were located in the space where the ESP for unit 3 was located. The SDA and FF for unit 3 were located in the space allotted for the APC systems for unit 4. Thus the SDA and FF for unit 4 will have to be located north of unit 4 beside the Ash Handling Building. The logical place to locate the SCR system for the 4th MWC is presently occupied by the existing ID fan, lime silo, carbon silo, access stair case, pumps and utilities for unit 3. The only available space for the SCR system for the 4th MWC would be approximately 400 feet away from the 4th MWC on the west side of the Ash Handling Building and perimeter road. Alternatively, the Ash Handling Building could be relocated north to make room for the SCR system. In any case, extensive rearrangement of existing equipment, utilities and structures will be required to fit in the SCR system, particularly considering the large footprint required for the system. The capital costs presented in Table 3-8 include this degree of installation difficulty. The total capital investment includes the purchased cost of the equipment, the direct installation costs and the indirect costs and is equal to $22,985,000. The total capital investment is amortized at an interest rate of 7% over a 20 year period. The annualized capital cost is equal to $2,170,000.

Annual O&M costs were developed for operating and maintenance labor, maintenance materials, catalyst replacement, chemicals (aqueous ammonia), power, steam for flue gas heating, lost revenue attributable to SCR downtime, catalyst disposal, insurance, administration and regulatory compliance. The total annual O&M cost is equal to $3,521,000. Combining the annualized capital cost and the annual O&M cost yields a total annual cost of $5,691,000. Dividing the total annual cost by the tons of NO_x removed per year (405 tons) yields a total cost per ton of NO_x removed of $14,100. The unit cost for SCR at $14,100 per ton is significantly greater than the upper limit of economic feasibility, and therefore, SCR is judged to be not economically feasible.

The economic analysis of SNCR with FGR for the 4th MWC is presented in **Table 3-9**. The cost of the SNCR system is based on a budgetary estimate provided by Fuel Tech for their NOxOUT process. The NOxOUT process is based on the use of urea and some proprietary chemical additives which prevent scale formation and extend the effective temperature range of the SNCR process. The required equipment for the NOxOUT process would consist of the following:

- Urea storage tank
- Urea circulation module containing feed pumps and electric heaters
- Urea metering module containing metering pumps, water supply line and control valves, static mixers and booster pumps
- Three urea distribution modules for air atomization of the urea solution into the furnace and air cooling of the injector nozzles
- 21 urea injector assemblies
- NOx analyzer
- Instrumentation and controls

The purchase cost for the uninstalled SNCR system and FGR equipment is $1,045,000. The total capital investment including installation and indirect costs is $3,050,000. The total capital cost is annualized using an interest rate of 7% and an amortization period of 20 years. An SNCR system is vastly simpler than an SCR system and the capital and O&M costs reflect this difference. O&M costs are based on utility requirements provided in vendor supplied data. The total annual cost is $788,000 and the total cost per ton of NO_x removed is $2,400. The unit cost for SNCR is well within the range of economic feasibility and is therefore economically feasible.

It should be noted that the incremental cost of SCR above SNCR is calculated as follows:

($5,691,000 - $788,000) / (405– 324 tons of NO_x removed) = $60,530/ton of NOx

The incremental cost of $60,530 per ton of NO_x removed demonstrates that SCR represents an exorbitant cost for a relatively modest amount of additional NOx removal.

3.7.6 Energy Impact

SCR will use significantly more electrical energy (616 kilowatts) than SNCR which will use 75 kilowatts. The greater electrical energy usage for SCR over SNCR is due to the increased fan static pressure needed to overcome the pressure drop across the catalyst bed and for power for pumps and the evaporator blower. The SCR system will require a significant amount of flue gas reheat which will mostly be supplied by the flue gas to flue gas heat exchanger. However, the final temperature increment must be done by either burning a fossil fuel or using high pressure steam from the WTE facility. For this analysis, it was assumed that high pressure steam would be used for the final heating of the flue gas prior to the SCR catalyst. Approximately 11.5 MM Btu/hr of energy in the form of steam would be required. SNCR does not require flue gas reheat.

3.7.7 Selection of BACT

Based on a review of environmental, economic and energy impacts, SCR is rejected as BACT for Unit 4 at the Facility and SNCR with FGR is determined to be BACT. Hillsborough County is proposing to install SNCR with FGR to meet an outlet NO_x emission level of 110 ppmdv at 7% O_2 averaged over a 24-hour period. This is an aggressive limit and will require 'fine tuning' of the SNCR with FGR control system.

3.8 BACT Review for Carbon Monoxide

CO is formed by the incomplete combustion (oxidation) of carbon containing compounds in the MSW fuel. Emissions of CO can potentially be reduced at municipal waste combustion facilities by two main methods: 1) utilizing good combustion design and operation to maximize the oxidation of CO to CO_2, and 2) reducing the quantity of CO in the post-combustion flue gas stream (flue gas controls).

Table 3-8

SCR with FGR System for 600 TPD Municipal Waste Combustor - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
SCR Supplier's Equipment: inlet & outlet ducts, heat exch. bypass duct, gas to gas heat exchanger, dampers, gas duct burners, flue gas & reagent mixers, reactor casing, catalyst, hoists, monorail, two aqua ammonia storage tanks, ammonia feed pumps & injection system, structural steel, stairs, platforms, instrumentation & controls, In Situ NOx analyzers,	$6,500,000	
FGR ducts and fan	$200,000	
Additional flue gas ductwork (580 ft at $1000/ft)	$580,000	
DCS interconnect	$50,000	
Increased ID fan size	$100,000	
Firewater booster pump	$25,000	
Sales Tax and Freight @ 8%	$596,000	
1. Purchased Equipment Cost = A	$8,051,000	
Direct Installation Costs		
Foundations 0.12xA	$966,000	
Structural Steel - Allowance for hurricane windloads 0.12xA	$966,000	
Handling and Erection 0.40xA	$3,220,000	
Retrofit existing plant site for SCR - Relocation of ext facilities 0.30xA	$2,415,000	
Electrical 0.08xA	$644,000	
Piping & Ductwork 0.35xA	$2,818,000	
Painting 0.02xA	$161,000	
Insulation 0.01xA	$81,000	
2. Total Direct Installation Cost	$11,271,000	
Indirect Costs		
Engineering 0.10xA	$805,000	
Construction and Field Expenses 0.20xA	$1,610,000	
Contractor Fees 0.10xA	$805,000	
Start-Up, Performance Test & Contingencies 0.05*A	$403,000	
Working capital (2 months supply of ammonia)	$40,000	
3. Total Indirect Cost	$3,663,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$22,985,000	
TOTAL ANNUALIZED CAPITAL COST (i =7%, 20 yrs, crf = 0.09439)		$2,170,000
ANNUAL O&M COSTS		
Operating Labor		
(8 hr/day x 365day/yr x $30/hr x 1.60 for fringe benefits)	$140,000	
Supervisory Labor		
(15% of operating labor)	$21,000	
Maintenance Labor		
(12 hr/day x 365 days/yr x $35/hr x 1.60 f.b.)	$245,000	
Maintenance Materials (includes spare parts inventory replacement)		
(100% of maintenance labor)	$245,000	
Catalyst Replacement (i = 7%, 3 yrs, crf = 0.38105)		
($754,900 x 0.38105)	$288,000	
Chemicals - Aqueous Ammonia		
(56.9 lbs NH_3/hr x gal 19% NH_4OH solution/1.47 lbs NH_3 = 38.7 gal/hr)		
(38.7 gal NH_4OH/hr x 8760 hr/yr x $0.773/gal x 0.92 avail.)	$241,000	
Power - Additional ID Fan Power cost		
(0.000157 x 167,700 acfm x 14 inches wc x 1/0.55 = 670 hp)		
(670 hp x 0.75 kw/hp x 8760 hr/yr x $0.06/kwhr x 0.92 avail.)	$243,000	
Power - for pumps, evaporator blower, FGR fan, I&C		
(114 kw x 8760 hr/yr x $0.06/kwhr x 0.92)	$55,000	
Steam for Flue Gas Heating - Lost Power Revenue		
(10,400 lb steam/hr x 1105 Btu/lb steam x kw-hr/10,560 Btu = 1088 kw)		
(1088 kw x $0.060/kwhr x 8760 hr/yr x 0.92 avail)	$526,000	
Lost Revenue from Combustor Unavailability due to SCR		
Tip Fee: 10 days/yr x 600 tons refuse/day x $56/ton refuse	$336,000	
Power: 10 daysx 600 tons/day x 2000 lbs/tonx 5000 Btu/lb = 6.0×10^{10} Btu		
(6.0×10^{10} Btu x kwhr/15,160 Btu x $0.06/kwhr)	$237,000	
Catalyst Disposal		
(enginering estimate)	$25,000	
Administration, Insurance & Regulatory Compliance		
(0.04 x Total Capital Investment)	$919,000	
TOTAL ANNUAL O&M COST		$3,521,000
TOTAL ANNUAL COST		$5,691,000
Tons of NOx Removed per Year		**405.0**
TOTAL COST PER TON OF NOx REMOVED		**$14,100**

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Table 3-9

SNCR with FGR for 600 TPD Municipal Waste Combustor - Capital and O&M Costs

CAPITAL COSTS		
Direct Costs		
Purchased Equipment Costs		
SNCR Supplier's Equipment: 15,000 gal urea storage tank, urea circulation/heating module, urea metering module, 3 distribution modules for air atomizing & cooling, 21 urea injector assemblies, temperature monitor, instrumentation & controls, NOx analyzer	$1,045,000	
FGR ducts and fan	$200,000	
Ammonia analyzer	$25,000	
Sales Tax and Freight	$102,000	
1. Purchased Equipment Cost = A	$1,372,000	
Direct Installation Costs		
Foundations and Supports 0.05xA	$69,000	
Steel Supports, Ladders and Platforms 0.06xA	$82,000	
Handling and Erection 0.30xA	$412,000	
Electrical 0.08xA	$110,000	
Piping & ductwork 0.25xA	$343,000	
Painting 0.02xA	$27,000	
Insulation 0.01xA	$14,000	
2. Total Direct Installation Cost	$1,057,000	
Indirect Costs		
Engineering 0.08xA	$110,000	
Construction and Field Expenses 0.20xA	$274,000	
Contractor Fees 0.10xA	$137,000	
Start-Up, Performance Test & Contingencies 0.05*A	$69,000	
Working capital (2 months supply of urea)	$31,000	
3. Total Indirect Cost	$621,000	
TOTAL CAPITAL INVESTMENT (1+2+3)	$3,050,000	
TOTAL ANNUALIZED CAPITAL COST (i =7%, 20 yrs, crf = 0.09439)		$288,000
ANNUAL O&M COSTS		
Operating Labor (2 hr/day x 365day/yr x $30/hr x 1.60 for fringe benefits)	$35,000	
Supervisory Labor (15% of operating labor)	$5,000	
Maintenance Labor (3 hr/day x 365 days/yr x $35/hr x 1.60 f.b.)	$61,000	
Maintenance Materials (100% of maintenance labor)	$61,000	
Power - for compressed air, urea feed and injection system (75 kw x 8760 hr/yr x $0.06/kwhr x 0.92 availability)	$36,000	
Chemicals - Urea (18.6 gal/hr x 8760 hr/yr x 0.92 avail x $1.20/gal)	$180,000	
Administration, Insurance & Regulatory Compliance (0.04 x Total Capital Investment)	$122,000	
TOTAL ANNUAL O&M COST		$500,000
TOTAL ANNUAL COST		$788,000
Tons of NOx Removed per Year		**324.0**
TOTAL COST PER TON OF NOx REMOVED		**$2,400**

3.8.1 Emission of Carbon Monoxide

CO is formed by incomplete oxidation of carbon compounds during combustion. The sources of carbon compounds during combustion are the solid waste, pyrolysis products formed near the fuel bed, or immediate combustion products. The emission of relatively high concentrations of CO is largely dependent on the underfire air dispersion to the combustor, the under/overfire air ratio, the design of the overfire air jets, and furnace combustion temperature. Careful operation of the furnace is essential to maintain good combustion practices (GCP). A low CO concentration is a good indication that furnace is achieving a high combustion efficiency; while a high CO concentration may indicate poor combustion and a potential increase in the level of trace organic emissions. In addition, elevated emissions of CO in municipal waste combustion facilities may be due to excessive carryover of particulate-bound organics from the furnace into lower temperature regions of the combustion system prior to completion of combustion (EPA, 1989d and EPA, 1995d).

Specific add-on technologies for controlling CO in the flue gas, such as thermal oxidizers and oxidation catalyst systems, have been applied to other combustion sources but, have not been used on MWCs. Although thermal oxidizers have been successfully applied to industrial sources these units generate increased electrical energy and fan power demands. In addition, thermal oxidizers produce secondary pollutant emissions. Oxidation catalysts are made from precious or semi-precious metals that tend to be easily poisoned by contaminants, such as sulfur, phosphorous and trace metals in the flue gas. These systems generally cannot be installed on sources burning sulfur emitting fuels. Therefore, these systems are not considered further in this BACT evaluation.

The ability of the furnace to minimize CO formation is a fundamental requirement of GCP. The occurrence of spatial and temporal temperature variations during normal operating conditions necessitates that municipal waste combustion facilities be designed and operated in a manner that will ensure that all combustion products are exposed to minimum destruction temperatures for sufficient residence times. Furnace combustion gas residence time is also an important requirement to ensure minimum CO formation. Emissions of CO are limited under EPA's definition of GCP. It involves continuous compliance of three parameters: a CO emission limit, a load limit, and a temperature limit at the inlet of the particulate matter control device. The use of GCP reduces CO emissions by promoting more thorough combustion (RTP, 2003).

3.8.2 Selection of BACT

Since no add-on CO control technologies have been deemed feasible for current MSW combustion facilities, GCP design and operation is determined to be BACT for CO. The BACT for CO will be achieved through the design and control of the combustion process. CO emissions will be limited to 80 ppmdv over a 12-month averaging period and 100 ppmdv over a 4-hour averaging period, exclusive of start-up, shutdown, and malfunction conditions. The emission rate for CO given in Section 4 represents the BACT as per PSD regulations and FDEP requirements.

3.9 BACT Review for MWC Organics

MWC organics including dioxins and furans are formed by incomplete oxidation of carbon compounds during combustion. Emissions of MWC organics can potentially be reduced at municipal waste combustion facilities by two main methods: 1) GCP which utilize good combustion design and operation to maximize the oxidation of CO to CO_2, and 2) flue gas controls, which reduce the quantity of MWC organics in the post-combustion flue gas stream.

3.9.1 Emission of MWC Organics

MWC organics are formed by incomplete oxidation of carbon compounds during combustion. The sources of carbon compounds during combustion are the solid waste, pyrolysis products formed near the fuel bed, or immediate combustion products. The actual formation of MWC organics in the flue gases is not well understood. MWC organics emissions are reduced by either GCP or GCP with post-combustion flue gas controls.

GCP is important to reducing dioxin formation by completely oxidizing the organic compounds and carbonaceous solids that are precursors to dioxin formation. Good combustion practice consists of "time, temperature, and turbulence" in the combustion chamber. Combustion temperatures approaching 1800° F (982°C) at residence times of 1 to 2 seconds will destroy most gas-phase compounds. Flue gas composition and process conditions downstream of the furnace/boiler section of MWC determine the extent of dioxin synthesis, which occur in the temperature range of 250° – 600° F (121-316°C). At higher temperatures chloro-organics are rapidly destroyed while at low temperatures the reaction rate is minimal. MWC facilities that use GCP and perform continuous emission monitoring can achieve dioxin emissions averaging 13 ng/dscm @ 7% O_2. GCP involves continuous compliance of three parameters: a CO emission limit, a load limit, and a temperature limit at the inlet of the particulate matter control device. All three of these continuous compliance parameters have been shown to correlate with either formation or emission of dioxins/furans (EPA, 1995d).

Post combustion control such as thermal oxidizers and oxidation catalyst systems for the removal of MWC organics in flue gas streams have not been employed on MWCs in the U.S. In addition, thermal oxidizers generate increased electrical energy and fan power demands, and they produce secondary pollutant emissions. Oxidation catalysts are made from precious or semi-precious metals that tend to be easily poisoned by contaminants, such as sulfur, phosphorous and trace metals in the flue gas. These systems generally cannot be installed on sources burning sulfur emitting fuels. Therefore, these systems are not considered further in this BACT evaluation.

3.9.2 Selection of BACT

Since no add-on MWC organics control technologies have been deemed feasible for current MSW combustion facilities, GCP is determined to be BACT for MWC organics. The BACT for MWC organics will be achieved through the advanced design of the combustion chamber and temperature control found in the Martin combustor.

MWC organics emissions will be limited to 0.1 lb of VOCs/ton and dioxins will be limited to13 ng/dscm at 7% O_2. The emission rate for MWC organics given in Section 4 represents the BACT as per PSD regulations and FDEP requirements.

3.10 BACT Review for Mercury Emissions

The combustion MSW generates mercury emissions, and its main source is discarded batteries in MSW. Most metals have low enough vapor pressures they condense on to PM, which makes it possible to be collected by the PM control device. However, mercury has a higher vapor pressure which makes its collection by PM control devices highly variable. Therefore, additional add-on control devices are typically installed to reduce mercury emissions. These add-on control devices include activated carbon injection, wet scrubber systems and carbon filter beds. A description of each control technology is presented below.

3.10.1 Emission of Mercury

Most metals have sufficiently low vapor pressures at typical air pollution control device operating temperatures that condensation onto PM is possible, except for mercury. Mercury has a high vapor pressure at typical air pollution control device operating temperatures, and collection by PM control devices is highly variable. Factors that enhance mercury control are low temperature in the air pollution control device system (less than 150 °C [300 to 400 °F]), the presence of an effective mercury sorbent and a method to collect the sorbent (Nebel and White, 1991). In general, high levels of carbon in the fly ash enhance mercury sorption onto PM. The ash is then removed by the PM control device. Additionally, the presence of HCl in the flue gas stream can result in the formation of mercuric chloride ($HgCl_2$), which is readily adsorbed onto carbon-containing PM. Conversely, sulfur dioxide (SO_2) in the flue gas can act as a reducing agent to convert oxidized mercury to elemental mercury, which is more difficult to collect (Schager, 1990) (EPA, 1997).

3.10.2 Available Control Technologies

Add-on controls to reduce mercury emissions from MWCs are discussed below. These include:

- Activated carbon injection upstream of the air pollution control device
- Wet scrubber systems
- Carbon filter beds

3.10.2.1 Activated Carbon Injection

Activated carbon injection involves the injection of powdered activated carbon into the flue gas upstream of an air pollution control device. Activated carbon is a specialized form of carbon produced by pyrolyzing coal or various hard, vegetative material (e.g., wood) to remove volatile material. After injection into the flue gas and adsorption of mercury and other contaminants, the activated carbon is captured in the

PM control device. The factors affecting the performance of activated carbon injection are the temperature of the flue gas, the amount of activated carbon injected, the concentration and species of mercury in the flue gas, the extent of the contact between the carbon and mercury and the type of carbon used. Flue gas temperature, as noted above, is important because mercury is a vapor at temperatures above 150 to 200 °C (300 to 400 °F). The flue gas temperature needs to be within, or preferably below this range for the mercury to adsorb onto the carbon. The injection of activated carbon into the flue gas can achieve at least 85 percent control of mercury emissions (EPA, 1997).

In addition to removing mercury, injection of activated carbon may increase the removal of chlorinated dioxins and furans and potentially other semivolatile organics. Data from tests with activated carbon injection on an MWC equipped with a SDA/ESP, show 95 to 98 percent reduction of dioxin and furans, versus a reduction of 78 to 80 percent without carbon injection (Richman et al., 1993). Furthermore the addition of carbon to MWCs has a minimal impact on the quantity of collected PM requiring disposal (EPA, 1997).

In developing the MWC emissions guidelines and NSPS for mercury emissions, EPA evaluated data and conducted tests of an activated carbon injection system at two U.S. MWCs (Stanislaus County, California and Camden County, New Jersey) and based on their evaluation of the test results has recognized activated carbon injection in combination with a FF as a very effective control system for mercury. This led to establishment of the Subpart Eb NSPS level of 0.08 milligrams per dry standard cubic meter (dscm) or 85 percent control, whichever is least stringent.

Furthermore, the Facility Units 1, 2 and 3 using activated carbon injection have demonstrated compliance with the NSPS Hg emission limits. Tested levels at Hillsborough County Units 1, 2 and 3 from 2000 to 2002 have ranged from 5.41 to 9.70 ug/dscm at 7% O_2. These outlet Hg emissions concentrations are well below the EPA NSPS and Florida Mercury Rule levels.

3.10.2.2 Wet Scrubber Systems

Wet scrubber systems can be used to control acid gases, metals, PM , and dioxins and furans. Wet scrubbers for the purpose of enhanced mercury control have not been applied to MWCs in the U.S., although they have been applied to MWCs in Europe. Soluble species of mercury compounds, such as $HgCl_2$ and mercuric oxide (HgO), can be effectively captured (greater than 90 percent) in the wet scrubber. However, if there is significant elemental mercury in the flue gas, collection efficiencies will be limited. The captured mercury is precipitated out during wastewater treatment through the use of several additives (e.g., sodium sulfide, trimercapto-s-triazine and dithiocarbamate) (Reimann, 1993), (EPA, 1997).

The use of wet scrubbers requires treatment of wastewater before it is disposed. Another concern with the wet scrubber option is dechlorination of dioxin and furan isomers. Dechlorination raises concerns because the lesser-chlorinated dioxin and furan congeners are believed to be more toxic. However, it is theorized that a reagent can be added to the scrubber water to control dioxin and furan shifts across all isomer classes (Krivanek, 1993) (EPA, 1997).

No other more recent data relative to Hg emissions reductions from MWCs equipped with wet scrubbers were identified that showed that potential for higher removal capability than activated carbon injection.

3.10.2.3 Carbon Filter Beds

Carbon filter beds have been developed in Europe for use as final cleaning stage to remove heavy metals (e.g., mercury), organic pollutants (e.g., dioxins and furans), and acid gases (e.g., SO_2, HCl) (Hartenstein, 1993). Three filter designs have been used in Europe: 1) cross flow, 2) counter current, and 3) counter-cross flow. Both the cross flow and counter-current flow designs have been applied to MWCs. Most of the information available on carbon filter beds pertains to the cross flow design (EPA, 1997).

Application of carbon filter bed technology to MWCs in Europe was undertaken primarily for the purpose of reducing emissions of residual organic compounds, in addition to reducing heavy metals and acid gases. This flue gas polishing step has been installed on some European MWCs in response to a political desire in several countries (including Germany, Austria, Switzerland and the Netherlands) to reduce all air pollutants to the maximum extent possible, typically without regard to cost or the effect on plant efficiency (Hartenstein, et al, 1996). No data has been identified that indicates that significant additional Hg removal would occur with the activated carbon reactor over carbon injection with a SDA/FF. In fact, with activated carbon in the filter cake of the FF, a similar effect of an activated carbon reactor is created. Thus, for purposes of this review, it is considered that activated carbon injection in conjunction with a SDA/FF would provide equivalent control as an activated carbon reactor (RTP, 2003).

A potential negative impact associated with the carbon filter technology is disposing of the spent carbon. Options for disposal include burning the carbon or disposing of it in a hazardous waste landfill. Another concern with this technology is the formation of "hot spots" in the bed that can result in bed fires. To monitor hot spot formation, carbon monoxide concentrations in the flue gas are monitored upstream and downstream of the carbon bed, and grate temperatures are measured (EPA, 1997).

3.10.3 Ranking of Alternative Control Technologies

Control of Hg emissions has been established through proper operation of acid gas/particulate control devices with low scrubber outlet temperature in conjunction with activated carbon injection. In addition, wet scrubbers or activated carbon reactors have not established a higher removal efficiency for Hg from MWC flue gases. Therefore, SDA/FF and additional control by reagent (activated carbon injection) ranks as the most effective or "top" technology for flue gas Hg removal.

3.10.4 Selection of BACT

The proposed control technology for Hg is injection of activated carbon in conjunction with a semi-dry scrubber system consisting of an SDA and FF is considered BACT. This technology is considered to be the most effective in controlling Hg, and therefore, represents the highest ranking control technology from a top-down BACT perspective.

Hg emissions will be controlled to a level of 0.134 mg/dscm corrected to 7% O_2 or 85 percent control, whichever is least stringent.

3.11 Summary of BACT Determinations

Table 3-10 below summarizes those pollutants that are subject to PSD review for the proposed Unit 4 project at the Facility. **Table 3-10** also includes a summary of the proposed control technology for each pollutant.

Table 3-10
Pollutants Applicable to PSD Review and Proposed Control Technology

PSD Pollutant	Proposed BACT
PM_{10}	FF
MWC Metals (as PM)	FF
MWC Acid Gases [a]	SDA/FF
SO_2	SDA/FF
SAM	SDA/FF
NO_x	SNCR/FGR
CO	GCP
Mercury	ACI
MWC Organics [b]	GCP

Note: [a] MWC Acid Gases as HCl, HF, and SO_2.
[b] MWC Organics as Total Dioxins and Furans (measured as total tetra- through octa- chlorinated dibenzo-p-dioxins and dibenzo furans).

Section 4
Emissions Estimates

4.1 Introduction

The combustion of municipal solid waste (MSW) results in emissions of air pollutants. The addition of a fourth municipal waste combustor (MWC) unit will increase the emissions from the Hillsborough County Resource Recovery Facility (Facility). However, state of the art air pollution control (APC) equipment will be installed to minimize the increase in emissions. Emissions reductions will be accomplished through GCP and the use of an APC system. The APC system will consist of an SDA/FF system, an ACI system, and an SNCR with a flue gas recirculation (FGR) system on the new MWC unit. The proposed control technologies and the expected control levels were described in Section 3 of this application. The estimated emission rates from the MWC units with the proposed APC system are discussed in Section 4.2. The estimated emissions from miscellaneous minor sources are discussed in Section 4.3. The discussion of emissions factors and rates presented in this section focuses primarily on pollutants of public health and regulatory concern. The equivalent annual and air dispersion modeling emission rate calculations are presented in **Appendix A**.

MSW is a heterogeneous mixture of materials, and the physics and chemistry of its combustion are very complex. The combustion process involves chemical reaction kinetics and equilibrium, combustor fluid mechanics, and heat transfer rates. Covanta, Inc. performed a mass-balance modeling analysis of the combustion process for a reference waste. Model results were used to estimate stack gas flow rates, temperature, and composition. The ultimate analysis for the reference waste used for Unit 4 is presented in Section 6. The results from the mass-balance modeling analysis along with stack test monitoring data from the Facility's existing MWC units, emissions data from comparable other facilities, and federal and state regulatory limits were used to calculate emission rates for Unit 4. The stack test monitoring data are presented in **Appendix A**.

4.2 Pollutant Emission Estimates- New Municipal Waste Combustor Unit

The emission estimates presented in this application were developed based on the evaluation of 11 worst-case operating conditions for the proposed Unit 4. The analysis considered variations in waste throughput, waste feed type, and heating values. Estimated emissions rates for Unit 4 were based on 115 percent of design heat release rate (287.5 MMBtu per hour) firing 660 tons per day (tpd) of waste at 5,227 Btu per pound and operations of 24 hours, 365 days per year. The modeled air flow rate at this load is 74,188 dry standard cubic feet per minute (dscfm) at 7 percent O_2.

As discussed in Section 2, EPA promulgated NSPS under 40 CFR 60 Subpart Eb for large MWC units (a combustion capacity greater than 250 tpd). The NSPS were also established to reflect Maximum Achievable Control Technology (MACT) and to specify emission levels for additional pollutants. Florida adopted the Subpart Eb regulations by reference in FAC 62-204.800(7). The APC system will be designed to achieve or be below the NSPS limits in a consistent manner. Emission estimates and limits for SO_2, HCl, Pb and Cd are based on the NSPS (40 CFR 60 Subpart Eb). Emission estimates for NO_x are based on a vendor guarantee for the proposed SNCR with FGR system. The Hg, PM, CO, HF and SAM emissions estimates are based on emissions limits from the Lee County Energy Recovery Facility (LCERF) PSD Air Construction Permit 0710119-002, AC, PSD-FL-151-C, October 13, 2003. The dioxins and furan emissions are based on congener percentages obtained from two years of stack test data from the Facility. Emissions of beryllium (Be) are based on stack test results for the existing HCRFF MWC Units 1, 2 and 3. Finally, VOCs emission estimates are based on a permit emission limit for the Harrisonburg, VA Resource Recovery Facility. The projected emission limits of pollutants from the proposed project are shown in **Table 4-1**.

The basis for the proposed emission limits is the NSPS (40 CFR 60 Subpart Eb). As described in the preamble to the December 19, 1995, Federal Register announcement promulgating this rule (Federal Register Vol. 60, No. 243, p. 65387), these limits are based on the best demonstrated performance at operating MWC facilities. EPA studies showing that MWC facilities can meet these limits, and other supporting data for the emission limits, are contained in Municipal Waste Combustion: Background Information for Promulgated Standards and Guidelines, EPA-453/R-95-0136, and Standard Form 83 Supporting Statement for ICR No. 1506.5-1995 Standards for New Municipal Waste Combustors (Subpart Eb), September 29, 1995, as well as other background documents contained in Dockets A-90-45 and A-89-08. These are EPA-recommended emission limits, supported by stack test data and documentation; thus, there is reasonable assurance that these emission limits are achievable. In addition, a professional engineer's seal is provided on the permit application forms (Volume III) to comply with FDEP requirements. Further, the full-service vendor will guarantee the proposed emission limits for which control equipment is specifically provided.

4.2.1 Particulate Matter and PM_{10}

When solid waste is burned, PM may originate from three sources: inorganic substances, organo-metallic substances, and unburned waste. Inorganic materials are not combusted; consequently, the majority of these materials exit the system primarily as bottom ash, with a small portion entrained in the flue gas stream and carried through the APC equipment for collection. Organo-metallic compounds appear as inorganic oxides or metal salts in the flue gas, resulting from high temperature oxidation. Unburned solid waste entrained in the combustion flue gas is a result of incomplete combustion and agglomeration of small particles. Trace metals in the solid waste also become entrained in the flue gas. Some trace metals also may be found adsorbed onto entrained solids.

Table 4-1
Proposed Emissions Limits and Air Dispersion Modeling Emissions Rates

	MWC Unit No. 4 Proposed Emission Limits		
Pollutant	**Flue Gas Concentration Limit @ 7% O_2**	**Equivalent Annual Emissions Rates^{1,2} (tons/year)**	**Air Modeling Emission Rate (g/s)**
Sulfur Dioxide (SO_2)	26 ppmdv (based on 80% reduction) [3,7]	84.3	2.42
Nitrogen Oxides (NO_x)	110 ppmdv [4]	256.1	7.37
Carbon Monoxide (CO)	80 ppmdv [3]	113.4	3.26
Particulate Matter (PM)	20.6 mg/dscm [3,5]	25.1	0.72
Dioxin [6]	13 ng/dscm [8]	1.58E-05	4.55E-07
Metals (as PM	20.6 mg/dscm [3,]	25.	0.72
Mercury (Hg)	0.028 mg/dscm [3] 0.134 mg/dscm based on 85% reduction [7,9]	1.63E-01	4.67E-03
Cadmium (Cd	0.02 mg/dscm[8]	2.43E-02	7.00E-04
Lead (Pb)	0.2 mg/dscm [8]	2.43E-01	7.00E-03
Hydrogen Chloride (HCl)	25 ppmdv [8] 60 ppmdv based on 95% reduction [7.9]	111.1	3.20
Hydrogen Fluoride (HF)	3.5 ppmdv [3]	3.5	0.102
Ozone (as VOCs)	0.1 lb/ton[1]	12.0	0.35
Sulfuric Acid Mist (SAM)	15 ppmdv [2]	74.4	2.1
Ammonia	50 ppmdv [3]	43.0	1.24

Notes:

[1] Estimated emission rates for MWC Unit 4 based on 115% of design heat release rate firing 660 tpd of waste at 5,227 Btu/lb and operation of 24 hours a day, 365 days per year. The modeled air flow rate at this load is 74,188 dscfm @7% O_2.

[2] Equivalent annual emission rates are not permit limits, but are for informational purposes only.

[3] Lee County Energy Recovery Facility Prevention of Significant Deterioration Air Permit Application, February 2003 and Lee County Resource Recovery Facility Air Construction Permit 0710119-002-AC, PSD-FL-151C, October 13, 2003.

[4] Based on a NOx concentration limit of 110 ppmv @7% O_2 for the selective non-catalytic reduction (SNCR) with flue gas circulation (FGR) system.
[5] For purposes of analysis, PM_{10} is equivalent to PM.
[6] Total tetra through octa PCDD and PCDF.
[7] Whichever is less stringent.
[8] Estimated emission rates for each MWC unit is based on New Source Performance Standards emission limits for "new" large MWC units.
[9] Uncontrolled concentration is based on 95% confidence interval of 2000-2002 stack test results for the existing Hillsborough County RRF MWC Units 1-3 multiplied by a factor of 1.5 (660 tpd/440 tpd) to account for increase capacity of the proposed Unit 4.
[10] Based on Harrisonburg, VA Resource Recovery Facility VOC emission limit of 0.1 lb/ton.

The size and quantity of particulates emitted from solid waste combustion depend upon such factors as flue gas residence time, underfire air velocity through the combustor system, oxidizing/reducing conditions within the furnace, temperature, flue gas mixing, boiler tube spacing, boiler configuration, flue gas velocity and the chemistry of the fuel, which is burned. If the combustion takes place at higher temperatures and with the proper quantity of oxygen, the result will be more complete combustion of the fuel, and a decreased particle mass. High combustion temperatures and long residence times allow for more complete burning of organic particles with a commensurate decrease in particle size. Boiler configuration (180 degree turns) and decreased gas velocity will allow the larger, heavier particles to fall out of the flue gases as they pass the boiler, but the majority move downstream to the SDA unit. Particulates collected in the bottom ash from the boiler section are mixed in the ash discharger with fly ash particulate matter collected by the SDA system. All collected flyash is conveyed by enclosed screw conveyors.

The proposed control technologies include a FF system to remove fly ash (including trace metals) from combustion flue gas and reaction products generated in the SDA. The estimated maximum PM concentration at the FF system outlet is proposed to be limited to 0.009 grains per dry standard cubic foot (gr/dscf) at 7 percent O_2. Emissions calculations are presented in **Appendix A**.

To perform a conservative assessment of ambient impacts from PM with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), it has been assumed in this application that all emissions of PM consist of PM_{10}.

4.2.2 Municipal Waste Combustor Acid Gases

The sulfur which contributes to pollutant emissions from solid waste combustion is chemically bound to other compounds. During combustion, a fraction of these elements escapes from the furnace as gaseous sulfur compounds while the remainder leaves as bottom or fly ash. The type of sulfur compounds released from the furnace is dependent on the presence of other gaseous compounds, combustion temperatures, and chemical (oxidizing or reducing) conditions in the furnace. Furnace conditions (oxidizing or reducing) directly influence the types of sulfur compounds, which may form and exit during combustion. Excess oxygen conditions typical of a solid waste combustor; generally result in the format on of SO_2 and SO_3 while reducing (oxygen deficient) conditions result in hydrogen sulfide (H_2S), carbonyl sulfide (COS) and elemental sulfur.

Various sulfur compounds are produced from direct combustion processes. Sulfur dioxide (SO_2)is the predominant form of sulfur compound released from the MSW combustion process. Some of the SO_2, when released into the ambient environment, reacts with atmospheric water vapor to form sulfuric acid. Sulfuric acid and emitted sulfuric acid mist may further react in the atmosphere to form sulfate salts, a particulate aerosol.

Chlorine, and fluorine are also chemically bound to other compounds. A portion of these substances are also released during combustion and escape the furnace in various forms. Similar to sulfur, emitted chlorine and fluorine react with water vapor to form hydrochloric acid (HCl) and hydrogen fluoride (HF). The presence of these acid gases in the atmosphere results in reduced visibility, material corrosion, sensitive organ irritation in humans and animals, and can add to acid rain/fog problems.

4.2.2.1 Sulfur Dioxide

Sulfur dioxide (SO_2) is formed in the furnace when sulfur in the solid waste oxidizes during combustion. The SDA in series with the FF system will be used to reduce SO_2 emissions. The flue gas containing SO_2 enters the SDA where it comes into contact with a finely atomized lime slurry.

The resultant reactions are:

$$Ca(OH)_2 + SO_2 + H_2O \rightarrow CaSO_3 \bullet 1/2H_2O + 3/2H_2O$$

$$CaSO_3 \bullet 1/2H_2O + 1/2O_2 + 3/2H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

The SDA in series with the FF system proposed for the Facility will provide stable and reliable control of SO_2 emissions. The SO_2 outlet concentration of Unit 4 is estimated to be at or below 26 ppmdv corrected to 7 percent O_2, assuming 80 percent control. Achieving at least an 80-percent reduction of SO_2 is consistent with the NSPS limit. This outlet concentration is based on the most recently approved permit limit for the LCERF by FDEP. The SO_2 emissions calculations are presented in **Appendix A**.

4.2.2.2 Sulfuric Acid Mist

When released into the environment, sulfur dioxide may react with water vapor to form sulfuric acid. Sulfuric acid may further react to form sulfate salts, a particulate aerosol. The SDA/FF system will control Sulfuric Acid Mist (SAM) emissions from Unit 4 to a maximum level of 15 ppmdv at 7 percent O_2. Emissions calculations are presented in **Appendix A**.

Hydrogen Chloride

Hydrogen chloride (HCl) is formed and emitted to the atmosphere during the combustion of waste materials containing chlorinated compounds (typically plastics). The SDA in series with the FF system will be used to reduce HCl emissions. The flue gas containing HCl will enter the SDA where it will come into contact with a finely atomized lime slurry. The resultant reaction is:

$$2HCl + Ca(OH)_2 \rightarrow CaCl_2 + 2H_2O$$

The latest three years (2000-2002) of stack test data for each of the existing MWC units at the Facility were reviewed to develop a reasonable upper bound HCl inlet gas concentration. Using the three-year average stack concentration for all three existing units, a 95-percent confidence interval (CI) statistical analysis was conducted on the stack test data. This 95-percent CI concentration was then multiplied by 1.5 (ratio of 660 tpd/440 tpd) to account for the increase design capacity of the Unit 4 compared to the existing MWC units. The maximum inlet HCl concentration was calculated to be approximately 1,204 ppmdv corrected to 7 percent O_2. The HCl outlet concentration from the SDA/FF system of the new MWC unit will be at or below 60.2 ppmdv corrected to 7 percent O_2, based on reduction of the maximum inlet concentration by 95 percent using the SDA/FF system. Achieving at least 95 percent reduction of HCl is consistent with the NSPS limit. The statistical analyses of the stack test data and the HCl emissions calculations are presented in **Appendix A**.

Hydrogen Fluoride

Hydrogen fluoride (HF) is formed and emitted to the atmosphere during the combustion of waste materials containing fluorinated compounds. The SDA in series with the FF system will be used to reduce HF emissions. The flue gas containing HF will enter the SDA where it will come into contact with a finely atomized lime slurry. The resultant reaction is:

$$2HF + Ca(OH)_2 \rightarrow CaF_2 + 2H_2O$$

The SDA/FF system will control HF emissions from Unit 4 to a maximum concentration level of 3.5 ppmdv at 7 percent O_2. This proposed level is based on the most recent approved permit limits for the LCERF by FDEP, and is lower than the existing HF permit limit of 6.74 mg/dscm (7.9 ppmdv) at 7 percent O_2. Emissions calculations are presented in **Appendix A**.

4.2.3 Carbon Monoxide

CO is formed by incomplete oxidation of carbon compounds during combustion. The sources of carbon compounds during combustion are the solid waste, pyrolysis products formed near the fuel bed, or immediate combustion products. The emission of relatively high concentrations of CO is largely dependent on the underfire air dispersion to the combustor, the under/overfire air ratio, the design of the overfire air jets, and furnace combustion temperature. Careful operation of the furnace is essential to maintain good combustion practices (GCP). A low CO concentration is a good indication that furnace is achieving a high combustion efficiency; while a high CO concentration may indicate poor combustion and a potential increase in the level of trace organic emissions.

The CO outlet concentration of Unit 4 is estimated to be at or below 80 ppmdv corrected to 7 percent O_2 (4-hour arithmetic block average), based on the most recent approved permit limit for the LCERF by FDEP. Emissions calculations are presented in **Appendix A**.

4.2.4 Nitrogen Oxides

Nitrogen oxides (NO_x) are produced in all combustion processes. There are two mechanisms by which NO_x are formed during combustion:

- Thermal NO_x are formed by high temperature oxidation of nitrogen in the combustion air.
- Fuel NO_x are formed by the oxidation of nitrogen in the fuel.

The two major factors affecting the formation of thermal NO_x are the oxygen concentration present in the combustion zone and the flame temperature. The rate of NO_x formation has been shown to be linearly dependent on the oxygen concentration when temperature is constant. Additionally, NO_x formation tends to increase significantly with increasing temperature (at temperatures approximately above 2,100 °F) in the presence of O_2. In addition to these characteristics, NO_x formation increases linearly with increasing residence time at temperatures conducive to thermal NO_x formation (Russell and Roberts, 1984). Fuel NO_x is formed when MSW containing nitrogen and its compounds is burned, and the nitrogen is oxidized in the process.

The NO_x outlet concentration from Unit 4 will be at or below 110 ppmdv corrected to 7 percent O_2, based on a vendor guarantee for the SNCR with FGR system. Emissions calculations are presented in **Appendix A**.

4.2.5 Municipal Waste Combustor Metals

Combustion of solid waste results in the emission of trace metals. These metals are present in both the combustible and non-combustible parts of the waste. During combustion, the non-volatile metals are distributed in two general areas: bottom ash and fly ash. Volatile metal emissions also occur as vapor phase emissions. Trace metals in the flue gas will be controlled by the SDA/FF system. The SDA will condition the flue gas and reduce its temperature to between 285 and 325°F. At that temperature, volatilized metals will condense on available PM to be collected in the FF system.

The NSPS specify emission limits for Hg, Pb, and Cd. The Florida Mercury Rule (Section 62-296.416 FAC) provides additional emission limits for mercury emissions. Emissions of Be for the existing MWC units are limited by the PSD permit; however, Be emissions for Unit 4 will be based on stack test monitoring data for the existing MWC units. The other metals are regulated by the particulate control standard established by the NSPS (see Section 4.2.1). The emission rates for Hg, Pb, Cd, and Be are discussed below.

Mercury

Mercury (Hg) is a trace metal found in solid waste. Its origin is attributable to many different waste materials. Within the temperature range of the combustion process for solid waste, mercury is found as a metallic vapor. The melting point and boiling point of mercury are -38.0°C (-36.4°F) and 356.9°C (674°F), respectively (Perry and Chilton, 1973).

The Hg outlet concentration from Unit 4 will be at or below 0.028 mg/dscm corrected to 7 percent O_2 based on the most recently approved permit limit fro the LCERF by FDEP. The ACI system proposed for the Facility will provide stable and reliable control of Hg emissions. Similar to the methodology used to calculate the HCl inlet gas concentration, the maximum inlet Hg concentration was calculated to be approximately 0.89 mg/dscm corrected to 7 percent O_2. The Hg outlet concentration from the ACI system of the new MWC unit will be at or below 0.134 mg/dscm corrected to 7 percent O_2, based on reduction of the maximum inlet concentration by 85 percent using the ACI system. Achieving at least 85 percent reduction of Hg is consistent with the NSPS limit. Unit 4 will meet the less stringent of the two outlet concentration limits. The statistical analyses of the stack test data and the HCl emissions calculations are presented in **Appendix A**.

Lead

Lead (Pb) is a trace metal found in solid waste. Pb emissions are directly proportional to the content of Pb in the solid waste . The melting and boiling points of Pb are 327.5°C (621.5°F) and 1,620°C (2,948 °F), respectively (Perry and Chilton, 1973). Lead will liquidify during combustion and, due to its vapor pressure, some volatilization with subsequent condensation and solidification onto fly ash will occur. Liquid Pb will either become part of the bottom ash or adhere to the fly ash which will be collected in the SDA and FF system.

It has been shown that an SDA followed by a FF system results in a high degree of Pb removal from combustion flue gas (NITEP, 1986). The Pb outlet concentration from the SDA/FF system of Unit 4 will be at or below 200 µg/dscm corrected to 7 percent O_2, consistent with the NSPS limit. Emissions calculations are presented in **Appendix A**.

Cadmium

Cadmium (Cd) is present in both the combustible and non-combustible parts of the solid waste stream and is, for the most part, collected in the FF system. The Cd outlet concentration from the FF system of Unit 4 will be at or below 20 µg/dscm corrected to 7 percent O_2, consistent with the NSPS limit. Emission calculations are presented in **Appendix A**.

Other trace metals are controlled with the FF, and compliance is verified by the PM standard.

4.2.6 Municipal Waste Combustor Organics

The principal compounds of MWC organics of concern are dioxins and furans. The NSPS specifies limits for total emissions of all tetra- through octa-isomers of dioxins and furans. The dioxins and furans adsorbed on fly ash will be removed from the flue gas with the PM in the FFs. Removing dioxins and furans from the gaseous phase can be accomplished with scrubbers in combination with FFs. The ACI system may also provide some reduction in dioxin/furan emissions.

MWC organics are formed by incomplete oxidation of carbon compounds during combustion. The sources of carbon compounds during combustion are the solid waste, pyrolysis products formed near the fuel bed, or immediate combustion products. The actual formation of MWC organics in the flue gases is not well understood. MWC organics emissions are reduced by either GCP or GCP with post-combustion flue gas controls.

GCP is important to reducing dioxin formation by completely oxidizing the organic compounds and carbonaceous solids that are precursors to dioxin formation. GCP consists of "time, temperature, and turbulence" in the combustion chamber. MWC facilities that employ GCP and perform continuous emission monitoring can achieve dioxin emissions averaging 13 ng/dscm corrected at 7 percent O_2. GCP involves continuous compliance of three parameters: a CO emission limit, a load limit, and a temperature limit at the inlet of the particulate matter control device. All three of these continuous compliance parameters have been shown to correlate with either formation or emission of dioxins/furans (EPA, 1995d). The use of GCP reduces emissions of MWC organics by promoting thorough combustion, minimization of particulate carryover and condensation of vapor phase constituents through FF temperature control. Unit 4 will employ GCP in combination with the ACI/SDA/FF system to minimize dioxin and furan formation and emissions. GCP will include providing sufficient oxygen for the destruction of organic species, limiting PM carryover, and monitoring PM inlet temperature to minimize post-combustion dioxin/furan formation.

The dioxin and furan (total) outlet concentration from the SDA/FF system of Unit 4 is estimated to be at or below 13 ng/dscm corrected to 7 percent O_2, which is consistent with the NSPS limits. Emissions calculations are presented in **Appendix A**.

4.2.7 Volatile Organic Compounds

Volatile organic compounds (VOCs) and other non-methane hydrocarbons (NMHC) are formed during the combustion of MSW and are present in the flue gas. The principal mechanism to control these organic compounds is GCP. GCP includes proper design and operation of MWC unit to maximize the thermal destruction of VOCs and NMHC.

The maximum potential VOC emission rate from Unit 4 is 0.1 lb/ton. This emission factor was obtained from the Harrisonburg, VA Resource Recovery Facility and represents the lowest VOC emission factor found on the EPA BACT/LAER

Clearinghouse database. The estimated VOC emissions rates are based on Unit 4's maximum design waste capacity of 660 tpd. Emissions calculations are presented in **Appendix A**.

4.2.8 Ammonia

The new MWC unit will have a SNCR with FGR system to control NO_x emissions. As discussed in Section 3.6, SNCR uses ammonia as a reagent to reduce NO_x emissions in the post combustion flue gas stream. The SNCR/FGR system will be designed and operated in a manner to minimize ammonia slip, which will not exceed 50 ppmdv corrected at 7 percent O_2. Emissions calculations are presented in **Appendix A**.

4.3 Pollutant Emission Estimates-Miscellaneous Sources

4.3.1 Lime Storage Silo

Unit 4 will use an SDA system to control acid gases and sulfur dioxide emissions. The use of the SDA system requires the receiving, storing, handling, and processing of pebble and dolomitic lime. Pebble and dolomitic lime are granular materials that are inherently dusty and capable of significant particulate emissions if not controlled. The Facility will incorporate highly effective controls to limit potential lime dust emissions.

The lime storage silos will be equipped with a FF system designed for an outlet grain loading of less than 0.015 gr/dscf and an air flow rate of approximately 1,200 scfm. These baghouses will control fugitive lime particulate emissions which are generated when delivery trucks are unloaded. Pressure drop monitoring across the FF systems will not be necessary. The inside volume of each silo will be approximately 2,900 cubic feet. Assuming that the pebble lime silo is filled every other day, the amount of air displaced out of the silo will be 2,900 dry standard cubic feet every other day. Therefore, the equivalent annual PM emission rate will be 5.67×10^{-4} tons/year based on this silo filling operation. Similarly, it is assumed that the dolomitic lime silo will be refilled every 30 days; therefore, the equivalent annual PM emission rate will be 3.78×10^{-5} tons/year. In actuality, the baghouses will be operated and emissions will occur only during filling operations. Emissions of this quantity are not considered excessive for these types of operations. The potential ambient impacts from these emissions sources are expected to be minimal.

4.3.2 Activated Carbon Storage Silo

Unit 4 will use a powdered ACI system for the control of mercury emissions. Operation of this system will require the installation of one silo for the storage of activated carbon before it is injected into the flue gas for mercury control. Powdered activated carbon will be delivered to the Facility by truck. Delivery of activated carbon will occur on a weekly basis. Emissions calculations are presented in **Appendix A**.

The activated carbon storage silo will be equipped with a FF system designed for an outlet grain loading of less than 0.015 gr/dscf and an air flow rate of approximately

1,200 scfm. This FF system will control fugitive powdered activated carbon particulate emissions which are generated when the delivery trucks are unloaded. Pressure drop monitoring across the FF system will not be necessary. The inside volume of the silo will be approximately 2,900 cubic feet. Because the silo is filled once a week, the amount of air displaced out of the silo will be 2,900 dry standard cubic feet per week. Based on this silo filling operation, the equivalent annual PM emission rate will be 1.62×10^{-4} tons/year. In actuality, the baghouse will be operated and emissions will occur only during filling operations. Emissions of this quantity are not considered excessive for this type of operation. The potential ambient impacts from these emissions are expected to be minimal. Emissions calculations are presented in **Appendix A**.

4.3.3 Cooling Tower Cell

Unit 4 will require a new cooling tower cell be installed at the Facility. It is anticipated that the annual emissions will be 0.42 tons/yr. An estimate of PM_{10} emission rates has been made based on cooling tower cell's design information and a methodology provided in AP-42, Section 13.4 (EPA, 1995). The manufacturer provided water flow and recirculation rates and also measured total dissolved solids (TDS) from the existing cooling tower cells at the Facility (since the new cooling tower cells will be identical to the existing cells). The new cell will also be equipped with a drift eliminator that will reduce PM_{10} emissions from the new cooling tower cell to 0.001 percent of the total potential PM_{10} emissions. A recent conference paper presented a methodology for computing realistic PM_{10} emissions from cooling tower cells with medium to high TDS levels (J. Reisman and G. Frisbee, 2000). Based on the measured TDS from the new cooling tower cell (3,500 ppm), the percentage of drift PM that evaporates to PM_{10} is approximately 50 percent. Therefore for the new cooling tower, CDM assumed that the PM_{10} emissions will be equal to 50 percent of the total PM emissions. Emissions calculations are presented in **Appendix A**.

4.3.4 Auxiliary Burners

Unit 4 will be equipped with two natural-gas-fired auxiliary burners, each with a rated heat input capacity of 50 MMBtu/hr for a total heat input capacity of 100 MMBtu/hr. These burners are necessary for firing the combustor during startups and shutdowns, and to maintain furnace temperatures when sustained low-Btu wastes are encountered. The County is requesting that emissions due to startup, shutdown, and malfunction periods be limited to 3 hours per occurrence, consistent with NSPS requirements (rather than 2 hours per day, as suggested at FAC 62-210.700). The duration of warm-up periods (i.e., when only natural gas is being combusted and no MSW is being introduced into the combustor) is not limited by the NSPS requirements. As discussed in Section 2, the County is requesting permit limits which restrict the annual use of natural gas to less than 10 percent of the total annual capacity for each unit so that the NSPS Subpart Db requirements for NO_x do not apply. The anticipated time for boiler warm-up is expected to be approximately 8 hours.

Section 5
Ambient Conditions

5.1 Terrain Description

The elevation of the Hillsborough County Resource Recovery Facility (Facility) is approximately 35 feet above mean sea level. The terrain in the area of the Facility is generally flat, with elevations ranging from 25 feet above mean sea level to 40 feet above sea level within one kilometer of the Facility. To the north and south, the terrain remains generally flat, with little to no variation in elevation. To the west toward the City of Tampa and Tampa Bay, the elevation approach sea level. Just east of the Facility, the terrain is also generally flat. However, there are areas approximately 3 kilometers east of the Facility with terrain as high as 80 to 90 feet above mean sea level.

5.2 Meteorology and Climate

The Tampa area (28.0°N, 82.5°W) can be classified as having a maritime tropical (mT) climate. Annual average daily temperatures range from about 62°F (min) to 81°F (max) and the area receives an average of about 50 inches per year of rainfall. Winds are predominantly out of the east (easterly trade winds), however, sea breeze effects are significant and are a common diurnal occurrence near the coastline. Although frozen precipitation effectively never occurs, violent storms (tornadoes, tropical storms, hurricanes) are a concern during the spring, summer and fall months.

The relatively good air quality of the region can be attributed to a number of climatic factors. The unstable air in the region is conducive to vertical mixing and thus assisting in the dispersion of ground-level pollutants. Frequent rainfall cleanses the air by scavenging particulate matter and other soluble pollutants and precipitating these pollutants to the ground.

Meteorological data used for air dispersion modeling analyses is discussed in more detail in Section 6.

5.3 Ambient Air Quality Standards/Attainment Status

According to Federal and Florida Prevention of Significant Deterioration (PSD) regulations 40 Code of Federal Regulations (CFR) 51.166 and 62-212.400 Florida Administrative Code (FAC), an applicant for a PSD permit is required to conduct an air quality analysis to demonstrate that the emissions from the Facility will not cause or contribute to a violation of any applicable ambient air quality standard or PSD increment. An assessment of existing air quality and a dispersion modeling analysis are used to determine compliance with the New Source Review (NSR) regulations. Because this project exceeds the PSD significant net emissions increase threshold for all criteria pollutants, except for lead, the air quality assessment is only required for those pollutants. However, a full analysis of all criteria pollutants is provided here for information purposes.

The U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for certain "criteria" pollutants, as mandated by the Clean Air Act (CAA) Amendments of 1970. These standards have been set at two levels. Primary NAAQS are designed to protect public health with an adequate margin of safety. Secondary NAAQS are designed to protect the public welfare, including property, materials, and plant and animal life. The State of Florida has adopted State AAQS (FAAQS) that are at least as stringent as the NAAQS and incorporate both the Federal Primary and Secondary standards (62-204.240 FAC). The sulfur dioxide FAAQS for annual and 24-hour averaging periods are more stringent (lower) than the NAAQS. These National and Federal ambient air quality standards are shown in **Table 5-1**. The six criteria pollutants with National and Florida ambient air quality standards are sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), fine particulate matter less than 10 micrometers in diameter (PM_{10}), lead (Pb), and ozone (O_3). The ambient air quality standards for PM_{10} replaced the standards for total suspended particulates (TSP) in 1987 at the Federal level and in March 1996 at the State level.

Under Section 107 of the CAA, each state is required to develop an State Implementation Plan (SIP) which specifies how all areas within the state will achieve and maintain compliance with the NAAQS. For regulatory purposes under the SIP, all areas in the United States are designated as either attainment, non-attainment, or unclassifiable with the NAAQS for each criteria pollutant. Attainment areas are areas which are currently in compliance with the NAAQS, and continued compliance is expected under the SIP requirements. Non-attainment areas are areas which either do not comply with the NAAQS or which significantly contribute to nearby areas which do not comply with the NAAQS. Unclassifiable areas are areas where insufficient data exist to classify the area as either attainment or non-attainment and are generally presumed to be in attainment with NAAQS. In addition to attainment, non-attainment, and unclassifiable areas, certain areas are designated as "maintenance" areas. Maintenance areas are areas that have been re-designated from non-attainment to attainment or unclassifiable. Because they are transition areas, some non-attainment requirements continue to apply, particularly requirements for Reasonably Available Control Technology (RACT) for certain new and existing sources of emissions [FAC 62-204.320(1)(d)].

The County is part of the West Central Florida Intrastate Air Quality Control Region (AQCR), which also includes Citrus, Hardee, Hernado, Pinellas, Levy, Manatee, Pasco, Polk, and Sumter Counties (40 CAR 81.96). The attainment status of the project site for each criteria pollutant is shown in **Table 5-2**.

The project site and vicinity is considered to be in attainment with all NAAQS. There are no non-attainment areas in Florida for NAAQS. Maintenance areas for O_3, PM, and Pb exist in parts of Florida. The Facility is located within local maintenance areas for all three of these pollutants. These local maintenance areas are described in Table 5-2. The RACT requirements for these pollutants are discussed in Section 2.9.

Table 5-1
National and Florida Ambient Air Quality Standards

Pollutant	Avg. Time	Florida Standard[1]	National Primary Standard[2]	National Secondary Standard[2]	Significant Impact Level[3]	PSD Increments[4]	
						Class II	Class I
NO_2 ($\mu g/m^3$)	Annual	100	100	100	1	25	2.5
SO_2 ($\mu g/m^3$)	3-Hr	1300	-	1300	25	512	25
	24-Hr	260	365	-	5	91	5
	Annual	60	80	-	1	20	2
CO ($\mu g/m^3$)	1-Hr	40000	40000	-	2000	-	-
	8-Hr	10000	10000	-	500	-	-
Pb ($\mu g/m^3$)	Qtr	1.5	1.5	1.5	-	-	-
O_3 (ppm)	1-Hr	0.12	0.12	0.12	-	-	-
	8-Hr	-	0.08	0.08	-	-	-
PM_{10} ($\mu g/m^3$)	24-Hr	150	150	150	5	30	8
	Annual	50	50	50	1	17	4
$PM_{2.5}$ ($\mu g/m^3$)	24-Hr	-	65	65	-	-	-
	Annual	-	15	15	-	-	-

Notes:

All short-term (1-hour, 3-hour, and 24-hour) standards except ozone are not to be exceeded more than once per 12 month period.

Annual standards are 12-month arithmetic means, never to be exceeded. Quarterly standards are also never to be exceeded.

The 1-hour ozone standard should not be exceeded more than an average of one day per year over three years.

The 8-hour primary and secondary ozone standards are based on the fourth-highest daily maximum 8-hour average ozone concentration.

The National NO_2 standard is promulgated at 0.053 ppm.

1 ppm NO_2 = 1887 $\mu g/m^3$ NO_2

1 ppm CO = 1140 $\mu g/m^3$ CO

1 ppm O_3 = 1961 $\mu g/m^3$ O_3

Sources:

[1] FAC62-204.240.

[2] 40 CFR 50.

[3] 40 CFR 51.165(b)(2) for Class II Areas. Class I SILSs are provided by the National Park Service/Fish and Wildlife Services.

[4] 40 CFR 51.166(c)

Table 5-2
Attainment Status[1] for Areas Including the Hillsborough County Solid Waste Energy Recovery Facility

Pollutant	State Designation[2]	Federal Designation[3]
Total Suspended Particulate Matter (TSP)	Maintenance Area[4] (FAC 62-204.340(4)(b)1)	Cannot be classified[4]
Particulate Matter with Diameter Less Than 10 Microns (PM_{10})	Unclassifiable (entire state FAC 62-204.340(3)(a))	Cannot be classified
Particulate Matter with Diameter Less Than 2.5 Microns ($PM_{2.5}$)	--	Cannot be classified or attainment
Sulfur Dioxide (SO_2)	Unclassifiable[5] (FAC 62-204.340(3)(b)3)	Cannot be classified or attainment
Nitrogen Dioxide (NO_2)	Attainment (entire state FAC 62-204.340(1)(e))	Cannot be classified or attainment
Carbon Monoxide (CO)	Attainment (entire state FAC 62-204.340(4)(a)4.	Unclassifiable or attainment
Ozone (O_3) (8-hour)	Maintenance Area[6] (FAC 62-204.340(4)(a)4)	Unclassifiable or attainment
Ozone (O_3) (1-hour)	--	Unclassifiable or attainment
Lead (Pb)	Maintenance Area[7] (FAC 62-204.340(4)(c)) Unclassifiable (entire state FAC 62-204.340(3)(c))	Cannot be classified

Notes:

[1] Florida Administrative Code (FAC) Chapter 62-204 and Code of Federal Regulations (CFR) Title 40, Part 81.310. EPA defines Hillsborough County as part of the West Central Florida Intrastate Air Quality Control Region (40 CFR 81.96).

[2] As of March 13, 1996.

[3] As of January 5, 2005.

[4] That portion of Hillsborough County within 12 kilometers (km) of the intersection of US 41 South and State Road 60.

[5] Local unclassifiable areas for SO_2 include Hillsborough County and the southwest corner of Pasco County.

[6] Local maintenance area for O_3 includes Hillsborough and Pinellas Counties.

[7] Areas within 5 km of UTM Zone 17 coordinates of 364.0 km east and 3093.5 km north

5.4 Existing Air Quality

Existing air quality in the Facility vicinity can be evaluated by comparing monitored ambient pollutant concentrations to ambient air quality standards (AAQS). The Air Quality Division of the Hillsborough County Environmental Protection Commission operates a network of ambient air monitoring stations. Air quality data for these stations are available from the U.S. EPA's AIRDATA internet-based database. These monitoring sites are listed in **Table 5-3** along with their Universal Transverse Mercator (UTM) coordinates. **Table 5-4** identifies the pollutants monitored at each of the Hillsborough County monitoring stations. **Table 5-5** shows the maximum highest and second-highest short-term and maximum annual concentrations measured at the closest monitoring site to the Facility for each pollutant. Monitoring data available for the most recent three-year period (2001- 2003) are presented.

A comparison of ambient monitoring data is shown in Table 5-5. Recent data shows the air quality in the vicinity of the Facility is good and improving each year. Sulfur dioxide (SO_2) emissions are primarily produced by combustion of sulfur-containing fossil fuels. SO_2 emissions can contribute to the formation of atmospheric haze and acid rain. Maximum SO_2 concentrations measured at the nearest monitoring station during the past three years were about 24%, 24%, and 18% of the National or State AAQS for the 3-hour, 24-hour, and annual averages, respectively.

Nitrogen dioxide is also typically emitted by combustion sources. Nitrogen dioxide is a component in the formation of photochemical smog and a contributor to the formation of acid rain. Maximum NO_2 concentrations measured at the nearest monitoring station during the past three years were about 20% of the National and State AAQS for annual averages.

Localized CO concentrations tend to be associated with vehicle emissions. Maximum CO concentrations measured at the nearest CO monitoring station during the past three years were about 20% and 50% of the National and State AAQS for the 1-hour and 8-hour averages, respectively.

PM_{10} and $PM_{2.5}$, or fine particulate matter, consists of soot, acidic particles, fine dusts and other aerosols. Maximum PM_{10} concentrations measured at the nearest monitoring station during the last available three years were 73% and 58% of the National and State AAQS for the 24-hours and annual averages, respectively. Maximum $PM_{2.5}$ concentrations measured during the last available three years were 55% and 91% of the National AAQS for the 24-hour and annual averages, respectively.

Lead (Pb) emissions have historically been associated primarily with motor vehicles using leaded gasoline. These emissions have greatly declined in recent years due to the use of unleaded fuel. A local Pb nonattainment area existed, until January 1996, around a battery recycling facility near McKay Bay in Tampa. This area has since been redesignated as unclassifiable. During the last three years, the maximum Pb level measured at the nearest Pb monitor in Hillsborough County was about 33% of the National and State AAQS for quarterly averages.

Oxides of nitrogen and volatile organic compounds (VOCs) are primary precursors to ozone formation. Ozone is not emitted directly into the atmosphere but is formed in the troposphere through the photolysis. When photolysis occurs, sunlight causes NO_2 to split into NO and O. The atomic oxygen (O) product is highly reactive and readily combines with molecular oxygen (O_2) to form ozone (O_3). VOCs react with hydroxyl groups (–OH) in primary reactions to form the NO_2 to ultimately yield O_3. In urban areas, the primary source of NO_x is combustion-related sources such as motor vehicles and industrial sources as discussed earlier. VOCs are emitted from motor vehicles, combustion sources, consumer products, and industrial processes.

The highest and second-highest 1-hour ozone concentrations measured at the nearest O_3 monitor station during the last three years have been less than the National and State AAQS. In addition, there have been no exceedances of the 8-hour standard during the past three years. The 8-hour ozone standard is based on the fourth-highest daily maximum 8-hour average ozone concentration. Recent ambient ozone data for Hillsborough County indicate compliance with the 1-hour ozone NAAQS (*i.e.*, number of days with ambient measurements above the AAQS at any one location were less than or equal to 1.0 when averaged over a three year period).

The **BOLD** numbers in **Table 5-5** are those selected to be used as background concentrations to be added to the Facility's predicted concentrations in the dispersion modeling analysis for NO_2, SO_2, CO, PM_{10} and $PM_{2.5}$. The selected concentrations are the annual average concentrations, and the maximum second-highest short-term concentration, over all three years. Since the air quality monitoring stations represented in Table 5-4 are in more urban areas than is the Facility site, the selected values are conservative representations of background air pollutant concentrations near the Facility.

Table 5-3
Locations of Ambient Pollutant Monitors and Relative Distance to Stack Location at the Hillsborough County Resource Recovery Facility

Stack Location	UTME (km)	UTMN (KM)
Ganon-5012 Causeway Blvd.	368.109	3092.890

Monitor Locations – Hillsborough County

Address	City/Town	UTME (km)	UTMN (km)	Distance from Stack (km)
6811 East 14th Avenue	Tampa	364.317	3094.012	3.955
1700 North 66th Street	Tampa	364.009	3093.400	4.132
2929 S. Kingsway Avenue	Brandon	374.239	3094.212	6.271
5012 Causeway Blvd Tampa Florida	Tampa	362.103	3089.236	7.030
Hwy 41 (Gibsonton)	Ruskin	362.095	3086.096	9.073
1167 North Dover Road	Plant City	378.978	3093.835	10.910
Gardinier Park U S 41 & Riverview Dr.	Tampa	363.697	3082.724	11.082
900 Harbour Island Blvd. (Athletic Club)	Tampa	357.443	3090.490	10.933
6700 Whiteway Drive Tampa	Tampa	364.558	3103.335	11.032
1105 E Kennedy Blvd	Tampa	356.641	3092.070	11.497
Coast Guard Station Davis Island	Tampa	356.862	3089.913	11.634
9851 Highway 41 South	Tampa	363.764	3081.892	11.825
4702 Central Ave. Seminole Adult Day Sch	Tampa	356.994	3096.498	11.686
Ballast Point Park Interbay Blvd.	Tampa	354.181	3085.328	15.848
3910 Morrison Ave.	Tampa	351.455	3090.409	16.838
Eisenhower Jr High School	Tampa	365.195	3074.797	18.326
5121 Gandy Blvd	Tampa	348.556	3086.043	20.717
One Raider Place Plant City, Fl	Plant City	389.292	3096.710	21.525
4013 Ragg Rd., Tampa	Tampa	352.261	3109.298	22.812
14063 County Road 39	S. Lithia	385.500	3073.259	26.226
E.G. Simmons County Park	Tampa	355.574	3069.060	26.926

Table 5-4
Pollutants Monitored at
Hillsborough County Ambient Monitors (2002-2004)

Monitor Address	**City**	**NO_2**	**SO_2**	**CO**	**Pb**	**O_3**	**PM_{10}**	**$PM_{2.5}$**
6811 East 14th Avenue	Tampa				X			
1700 North 66th Street	Tampa				X			
2929 S. Kingsway Avenue	Brandon						X	
5012 Causeway Blvd	Tampa		X				X	
Hwy 41 (Gibsonton)	Ruskin						X	
Gardinier Park U S 41 & Riverview Dr.	Tampa						X	
900 Harbour Island Blvd. (Athletic Club)	Tampa						X	
6700 Whiteway Drive	Tampa							X
1105 E Kennedy Blvd	Tampa						X	
Coast Guard Station Davis Island	Tampa		X			X	X	
9851 Highway 41 South	Tampa		X					
4702 Central Ave. Seminole Adult Day Sch	Tampa			X			X	
Ballast Point Park Interbay Blvd.	Tampa		X					
3910 Morrison Ave.	Tampa						X	X
Eisenhower Jr High School	Tampa						X	
5121 Gandy Blvd	Tampa	X	X			X		
One Raider Place	Plant City		X	X		X		
4013 Ragg Rd.	Tampa						X	
14063 County Road 39	S. Lithia					X		
E.G. Simmons County Park	Tampa	X	X			X		

Note: Ambient monitoring stations with bold X represent those monitors used to represent ambient conditions near the Facility.

Table 5-5
Ambient Monitored Concentrations at the Nearest Stations to the Hillsborough County Resource Recovery Facility

		2001		2002		2003		
Pollutant	**Avg. Time**	**High**	**2nd High**	**High**	**2nd High**	**High**	**2nd High**	**AAQS[1]**
NO_2 (µg/m^3)	Annual	21	-	21	-	19	-	100
SO_2 (µg/m^3)	3-Hr	317	309	288	253	200	189	1300
	24-Hr	61	59	51	48	48	32	260
	Annual	11	-	11	-	8	-	60
CO (ppm)	1-Hr	5.8	5.1	5.3	5.3	7.3	5.7	35
	8-Hr	3.1	3	4.5	3.8	3.6	3.3	9
Pb (µg/m^3)	Qtr	0.47	-	0.41	-	0.25	-	1.5
O_3 (ppm)[2]	1-Hr	0.126	0.11	0.091	0.087	0.108	0.107	0.12
	8-Hr	0.098	0.081	0.07	0.065	0.08	0.072	0.08
PM_{10} (µg/m^3)	24-Hr	109	103	37	35	42	41	150
	Annual	29	-	20	-	22	-	50
$PM_{2.5}$ (µg/m^3)	24-Hr	35	31	35	33	36	34	65
	Annual	11.7	-	10.8	-	10.5	-	15

Concentrations reflect the closest monitors to the Facility for each pollutant. Locations are shown below. See Table 5-3 for actual distances to the HCSWERF stack.

NO_x - Tampa 5121 Gandy Blvd. (348.556 km UTM Easting, 3086.043 km UTM Northing)

SO_2 - Tampa 5012 Causeway Blvd. (362.103 km UTM Easting, 3089.236 km UTM Northing)

CO - Tampa 4702 Central Ave (356.994 km UTM Easting, 3096.498 km UTM Northing)

Pb - Tampa 6811 East 14th Avenue (364.317 km UTM Easting, 3094.012 km UTM Northing)

O_3 - Tampa Coast Guard Station Davis Island (356.862 km UTM Easting, 3089.913 km UTM Northing)

PM_{10} - Brandon 2929 S. Kingsway (374.239 km UTM Easting, 3094.212 km UTM Northing)

$PM_{2.5}$ - Tampa 6700 Whiteway Drive (364.558 km UTM Easting, 3103.335 km UTM Northing)

Note:

[1] The Ambient Air Quality Standards (AAQS) shown are the more stringent of the National primary or secondary AAQS or the state AAQS.

[2] The 8-hour ozone standard is based on the fourth-highest daily maximum 8-hour average ozone concentration.

Section 6
Air Quality Modeling Analyses

6.1 Overview

As discussed in Section 1, the County is proposing to install a new municipal solid waste (MSW) combustion unit at the Hillsborough County Resource Recovery Facility (Facility). The Facility currently operates three 400-ton-per-day MSW combustion units. The new 600-ton-per-day fourth unit is necessary to meet the County's growing solid waste disposal needs. The expansion will result in a net increase of actual emissions from the Facility for all criteria pollutants. The existing Facility is a "major" source of air emissions, and some of the proposed emission rate increases would be "significant," as defined in the Prevention of Significant Deterioration (PSD) rules. Therefore, the proposed project would be subject to the PSD requirements under 40 CFR 51.165, 40 CFR 51.166, and Chapter 62-212, F.A.C.

The PSD preconstruction permit program requires that dispersion modeling be conducted for pollutants that would be emitted at "significant" rates in order to demonstrate the project's compliance with National Ambient Air Quality Standards (NAAQS), Florida Ambient Air Quality Standards (FAAQS), and Prevention of Significant Deterioration (PSD) Increments. Additionally, the analysis is performed to examine the impact of emissions of the proposed project on any Class I areas.

Maximum increases from the new municipal waste combustor unit (MWC) (herein referred to as Unit 4) criteria pollutant impacts were determined for comparison to significant impact levels (SILs) as required by the regulations and modeling guidance. These maximum increases are less than the SILs, so no cumulative modeling analysis was required. Although not required by the modeling guidance, modeling analyses were conducted for all four MWC units to demonstrate that the Facility will continue to comply with all AAQS and PSD increments. In addition, a comparison of maximum increases in facility impacts to the de minimis monitoring levels is included for PSD pollutants. Finally, a comparison of maximum increases in facility impacts to Florida Ambient Reference Concentrations (ARCs) guidelines is included for non-criteria pollutants. As of March 1, 2000, FDEP ruled that the ARCs are not rules nor do they implement any statutory authority. Nonetheless, the ARCs are still useful in evaluating the magnitude of non-criteria pollutant impacts.

6.2 Model Selection and Options

Modeling analyses were performed in three stages: (1) a screening analysis to determine the worst-case operating condition, (2) refined air quality analyses to demonstrate compliance with PSD increments and NAAQS, and (3) a Class I impact analysis to demonstrate impacts to areas of special national or regional value from a natural, scenic, recreational, or historical perspective. Class I areas are often federally protected parks and wildlife areas. The approach for each modeling analysis is discussed below

6.2.1 Screening Analysis

The SCREEN3 dispersion model (Version 96043) was used to conduct a first-level screening analysis to initially determine the worst-case Unit 4 operating condition. The SCREEN3 dispersion model is an interactive Gaussian plume model capable of predicting worst-case impacts for a single source using a set of predetermined meteorological conditions. Inputs to the SCREEN3 model include:

- Source parameters - stack height and exit diameter, gas exit temperature and velocity, emission rate
- Receptor parameters - downwind distances, elevations, flagpole heights
- Control options (downwash parameters).

A unit emission rate (1 g/s) was used. The SCREEN3 model also calculates impacts in the cavity region, the area of plume recirculation adjacent to a structure.

The screening analysis examined eleven combinations of load and MSW heating value to determine the worst-case operating condition. This is defined as the operating condition which produces the highest ground-level air pollutant concentrations. The parameters for the worst operating condition were used in the subsequent analyses.

6.2.2 Refined Air Quality Analyses

The refined air quality analyses were performed with actual hourly meteorological data to evaluate compliance with PSD Increments and NAAQS. The first step is to compare predicted ground-level air pollutant concentrations for the new sources alone with significant impact levels (SIL) for each criteria pollutant. If modeled concentrations from the new sources alone exceed the SILs, than a cumulative dispersion modeling analysis would be performed of emissions from both the proposed sources and from the existing sources within the significant impact area.

Steady-state Gaussian plume models are valid for distances up to 50 km. The assumption is that the transport time is less than or equal to the averaging time, since the plume is instantaneously assumed to travel any distance downwind. The preferred model for near source impact assessments is the Industrial Source Complex – Short Term (ISCST3) dispersion model. The ISCST3 model is a steady-state Gaussian plume model used to assess pollutant impacts from a variety of sources. This model can account for the following:

- Settling and dry deposition of particles
- Downwash
- Area, line and volume sources

- Plume rise as a function of downwind distance
- Separation of point sources
- Limited terrain adjustment.

ISC3 operates in both long-term and short-term modes. Regulatory "default" options were set in the ISCST3 model. This option automatically selects the use of stack tip downwash, final plume rise, buoyancy induced dispersion, the vertical potential temperature gradient, a treatment for calms, the appropriate wind profile exponents, the appropriate value for pollutant half-life, and a revised building wake effects algorithm.

Currently, Version 02035 of ISCST3 is used. The graphical user interface, ISC-AERMOD View, created by Lakes Environmental was used to facilitate model setup and post processing. ISCST3 was used in "refined" mode, with full receptor grids and five years of meteorological data.

Since the Facility will be operating all four units simultaneously, the existing three units were included in the refined air quality analyses.

6.2.3 Class I Impact Analysis

The Class I impact analysis is performed to protect areas of significant natural resources within 100 kilometers of the source. Compliance with PSD increments must be achieved, in addition to demonstrating that there are no significant adverse impacts to any air quality related value (AQRV) in the area. AQRVs are defined by the U.S. Forest Service as "features or properties of a Class I area that make it worthy of designation as a wilderness and that could be adversely affected by air pollution." Examples of AQRVs are visibility, odor, water, and flora and fauna. The evaluation of additional impacts in Class I areas is presented in Section 7.

When the averaging time (1-hour) is significantly less than the transport time to the Class I receptors, the steady-state premise of a Gaussian plume dispersion model fails. The Interagency Workgroup on Air Quality Modeling (IWAQM) and Florida DEP recommend the use of the CALPUFF modeling system for long range transport and impacts to Class I areas. CALPUFF is a multi-layer, multi-species non-steady-state puff dispersion modeling system that simulates the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF is intended for use on scales from tens of meters from a source to hundreds of kilometers. It includes algorithms for near-field effects such as building downwash, transitional buoyant and momentum plume rise, partial plume penetration, subgrid scale terrain, coastal interactions effects, and terrain impingement as well as longer range effects such as pollutant removal due to wet scavenging and dry deposition, chemical transformation, vertical wind shear, overwater transport, plume fumigation, and visibility effects of particulate matter concentrations.

The most recent available version of CALPUFF (currently Version 5.7 dated 030402) was used to assess impacts in the Class I areas. The ISCST3 input files were converted to

CALPUFF input files using the ISC2PUF program, and were run with three years of CALMET/MM5 meteorological data. The CALPOST program was used to extract the required concentration information from the hourly binary concentration file produced by CALPUFF.

Only the proposed Unit 4 was included in the Class I area air quality impact analysis.

6.2.4 Chemical Transformations

Section 6.2.4 of Appendix W to 40 CFR Part 51 outlines the acceptable procedures to obtain nitrogen dioxide (NO_2) impacts from emissions of oxides of nitrogen (NO_X). The initial screen is to assume all NO_X is converted to NO_2. Should NAAQS or PSD increments be exceeded, a conversion factor of 0.75 can be assumed. Should regulatory thresholds still be exceeded, a locally specific conversion factor can be calculated or the "ozone limiting method" can be used. It is expected that the assumption of 100% conversion of NO_X to NO_2 will produce conservative results. It is assumed that for the Class II analyses, the remaining criteria pollutants undergo no chemical transformations.

For the Class I impact analyses, the MESOPUFF II chemical transformation scheme incorporated into the CALPUFF model was used. CALPUFF internally converts sulfur dioxide to sulfate (SO_2 to $SO_4^=$) and nitrogen oxides to nitrate aerosol (NO_X to NO_3^-). To perform the conversions of NO_X to NO_3^-, CALPUFF requires input of background values of ozone (O_3) and ammonia (NH_3). Guidance (Earth Tech, 2001) recommends monthly values of O_3 and NH_3 be input; however, these monthly values are difficult to acquire. Thus, a single background O_3 value was used, and the CALPUFF model default NH_3 value was assumed.

6.2.5 Averaging Periods

The screening analysis produces 1-hour average concentrations, since the meteorological data is a 54-record statistical data set to be considered to produce "worst case" concentrations.

For the subsequent analyses, pollutant-specific averaging periods were selected based on applicable ambient air quality standards and PSD increments. Typically, the modeled averaging periods are 1-hour (for CO), 3-hours (SO_2), 8-hours (CO), 24-hours (SO_2 and PM) and annual (NO_2, SO_2 and PM). Although the Pb standard is based on a quarterly average, the maximum 24-hour concentration was used to conservatively determine compliance with the standard. Since the short term concentrations (3 to 24 hours) are not to be exceeded more than once per year, the highest of the second highest concentrations at each receptor (H2H) are requested from the models. For annual concentrations, the highest concentration is used as that is the only averaged concentration and there is no second highest at each receptor.

FDEP guidance for calculating the PM_{10} 24-hour average is to use the highest of the second highest results over one year of meteorological data, or the highest of the sixth highest results over five years of meteorological data. (Cleve Holladay, FDEP, telephone conversation, January 7, 2005). Since five years of meteorological data were used, CDM compared the highest annual mean over five years to the annual concentration specified in the NAAQS (50 µg/m^3), and compared the highest of the sixth highest concentrations over five years to the 24-hour PM_{10} NAAQS (150 µg/m^3).

6.3 Facility Layout and Surrounding Terrain

Figure 6-1 shows a U.S. Geological Survey map of the area and the vicinity of the Facility. **Figure 6-2** presents a detailed layout of the Facility with the location of the sources, the areas of the Facility structure, nearby retention ponds, parking lots, and roadways. The property line is also shown.

The stack is approximately 420 feet (128 meters) from the closest northern property line, 490 feet (150 meters) from the closest southern property line, 600 feet (183 meters) from the closest western property line and 1,130 feet (344 meters) from the closest eastern property line. The stack is the primary source of air pollutant emissions. The Facility also has several minor particulate matter (PM) emissions sources:

- Two lime storage silos (two more will be added);
- One activated carbon storage silo (one more will be added); and
- A two-cell forced draft cooling tower (a third cell will be added).

The cooling tower is located approximately 110 meters west southwest of the stack, while the silos are located between the stack and the ash handling building. There is also an existing vent with a baghouse on the ash handling system building, which will not be changed with the project.

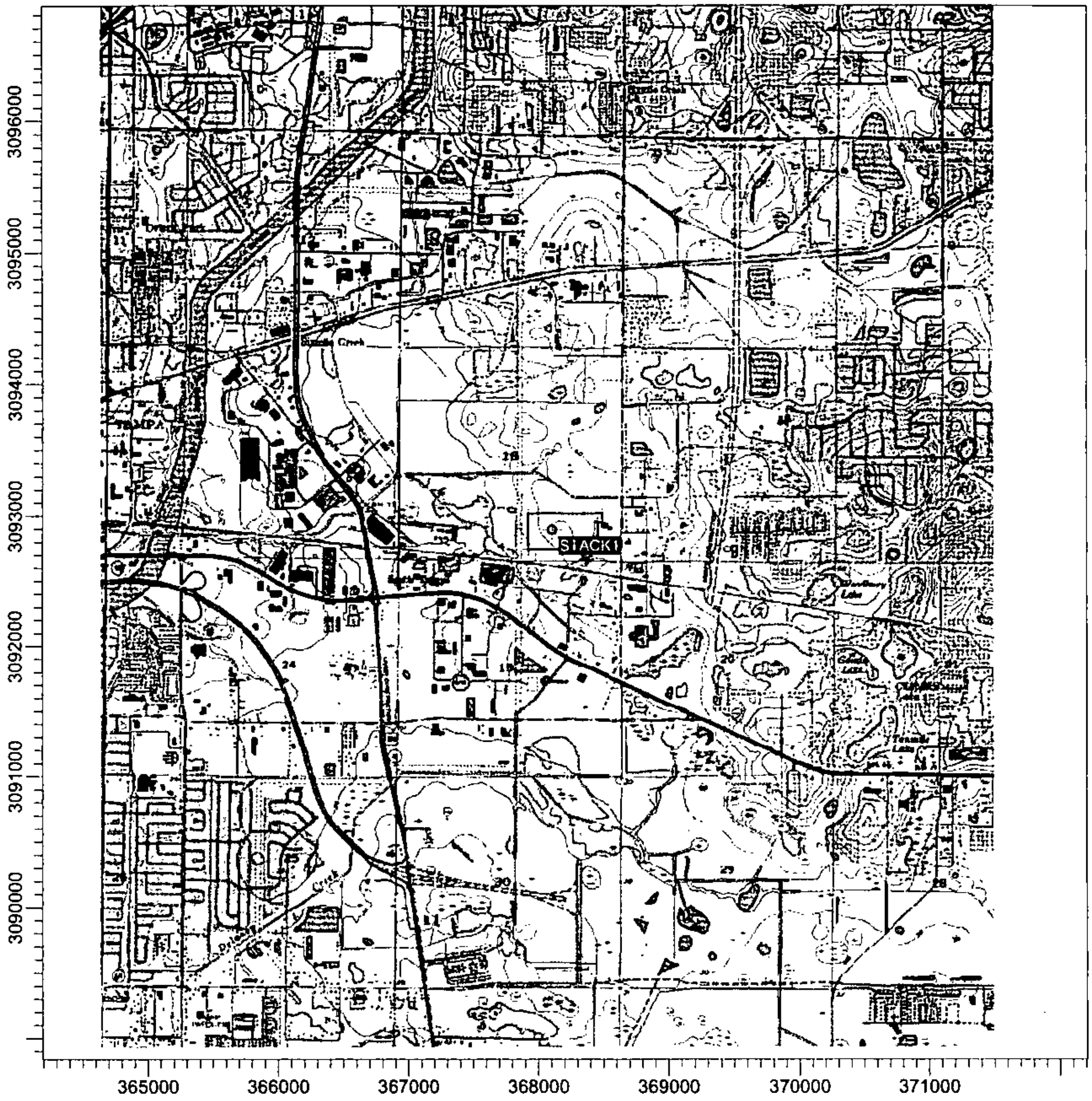
Although the terrain surrounding the facility is generally simple terrain (see discussion of terrain in Section 5) where there are areas to the east of the facility with elevations above stack base but below stack top (intermediate terrain). Thus, the option of using elevated terrain was used for the Class II modeling.

The Class I areas are approximately a minimum of 78 kilometers from the stack, and the general terrain of the Chassahowitzka Wildlife Refuge is approximately at sea level. The National Park Service has produced receptor files for this Class I area complete with terrain elevations. These terrain elevations were used in the Class I area modeling analysis.

The dispersion algorithms in the ISCST3 and SCREEN3 models are based on Pasquill-Gifford coefficients in rural areas and McElroy-Pooler coefficients in urban areas. Since CALPUFF was used in ISCST3 mode, this choice of dispersion coefficients also affected CALPUFF. Since more than 50% of the area within 3 km surrounding the stack can be classified as "rural", the rural (Pasquill-Gifford) dispersion coefficients was used in each dispersion model. **Figure 6-3** presents the land use within the 3-km radius of the stack. The areas shaded in red indicate "urban" uses.

PROJECT TITLE:

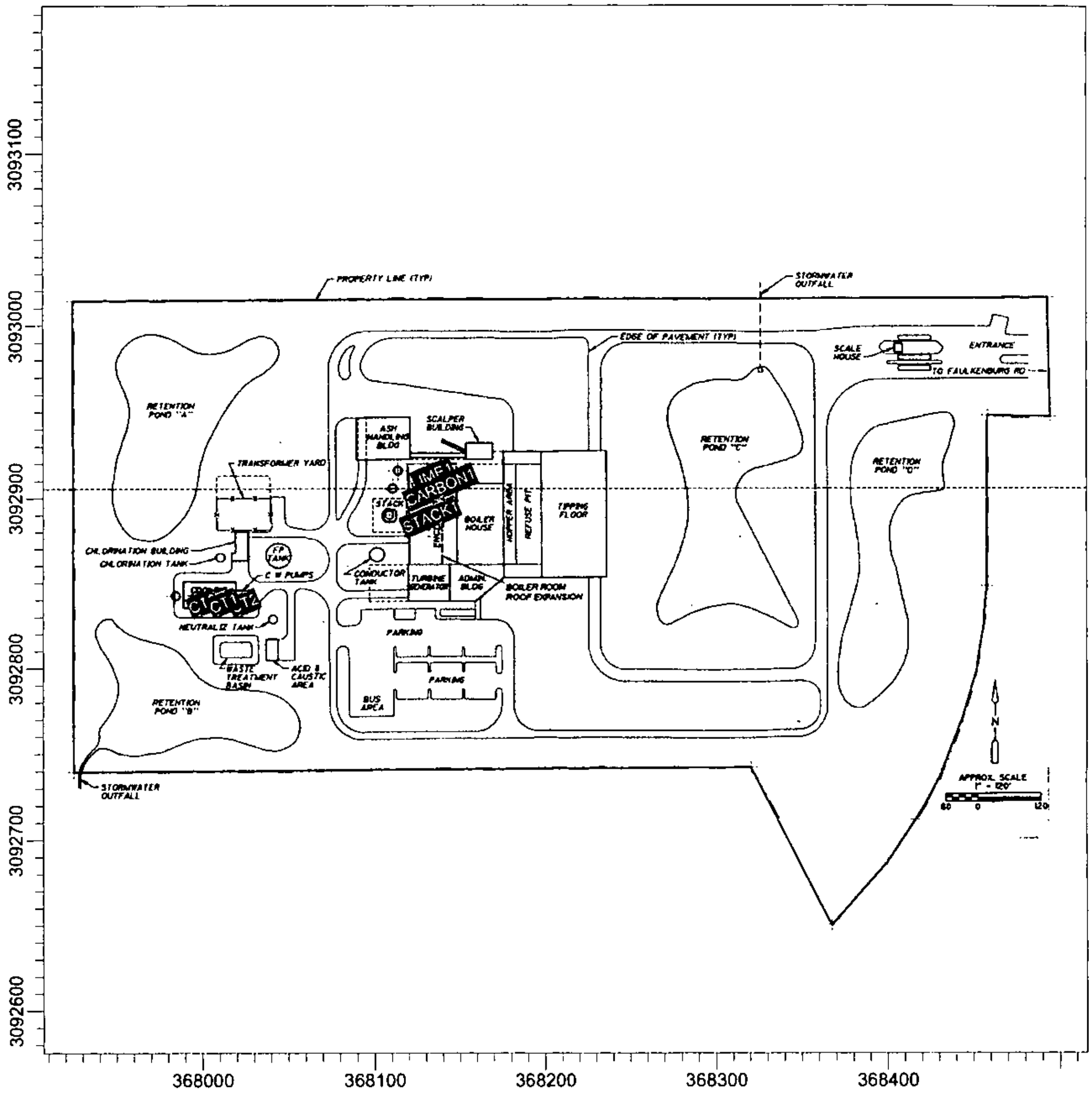
Hillsborough County Solid Waste Energy Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS: Figure 6-1 Locus Map	SOURCES : 1	COMPANY NAME: **CDM**	
	RECEPTORS : 1656	MODELER: **Vincent R. Tino, CCM**	CDM
		0 1 km	
		DATE: **8/12/2004**	PROJECT NO.: **6033-40441-FE.PSD.MODEL**

PROJECT TITLE:

Hillsboro County Solid Waste Energy Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS:

Figure 6-2

Site Plan Map

SOURCES : 6

RECEPTORS : 2557

COMPANY NAME: **CDM**

MODELER: **Vincent R. Tino, CCM**

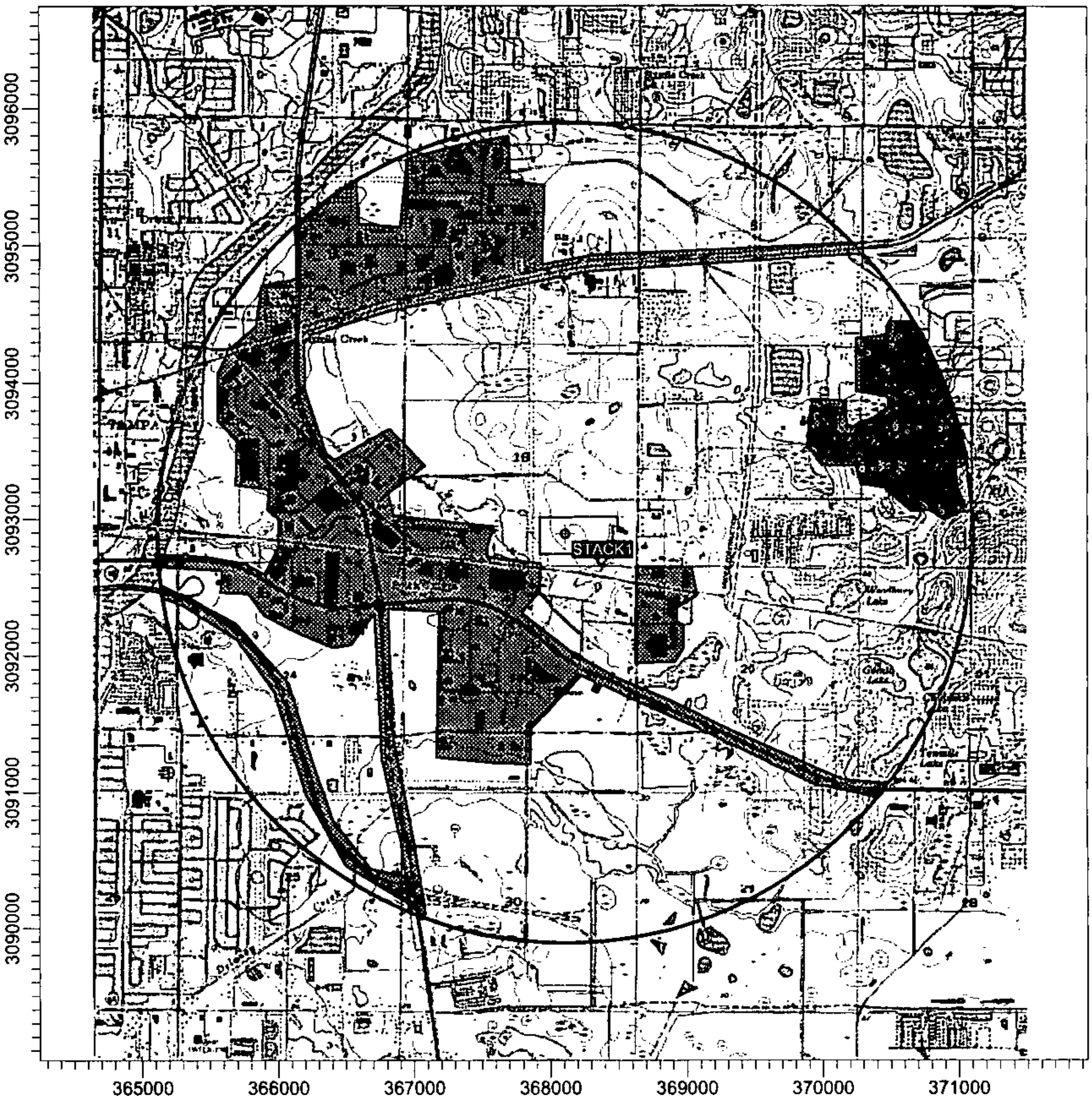
0 0.1 km

DATE: **1/11/2005**

PROJECT NO.: **6033-40441-FE.PSD.MODEL**

PROJECT TITLE:

Hillsboro County Solid Waste Energy Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS: Figure 6-3 3-km Land Use Area	SOURCES : 1	COMPANY NAME: **CDM**
	RECEPTORS : 1656	MODELER: **Vincent R. Tino, CCM**
		0 ——— 1 km
		DATE: **8/12/2004**
		PROJECT NO.: **6033-40441-FE.PSD.MODEL**

CDM

6.4 Source Data

The primary emissions source at the facility is the boiler stack. The stack height is 67 meters (220 feet) and contains four flues. Three of the flues are connected to existing combustor units and have inside diameters of 1.651 meters (5 feet, 5 inches) each. The proposed fourth unit will be connected to an existing flue which will be flared to an inside diameter of 2.261 meters (7 feet, 5 inches) to accommodate the increased combustor size.

The stack parameters used in the screening analysis were obtained from Covanta. These include estimates of stack gas temperature and flow rate based on waste heating values, throughput, and boiler configuration. The proposed Unit 4 will be capable of operating under a range of thermal loads from 60 percent to 115 percent of a nominal 250 million British Thermal Units per hour (MMBtu/hr) gross heat input, and MSW throughputs from 60 percent to 110 percent of a nominal 600 tons per day, based on a range of possible MSW heat content from about 3,800 to 6,000 Btu per pound of MSW. This operating window is presented in **Figure 6-4**.

The eleven operating scenarios for Unit 4 are shown in **Table 6-1**. Operating scenarios 3, 6, and 8 are not considered viable, and were not evaluated. For the screening modeling analysis, a unitized emission rate of 1.0 grams per second (g/s) was used for the 100 percent of design heat input cases as shown Table 6-1. Because air pollutant emission rates are proportional to the heat input rate, the unitized emission rate used, for Cases 4 and 5 was 0.6 g/s, for Case 7, 0.77 g/s, and for Cases 10 and 11, 1.15 g/s.

Table 6-1
Municipal Waste Combustor
Unit 4 Operating Window & Stack Parameters

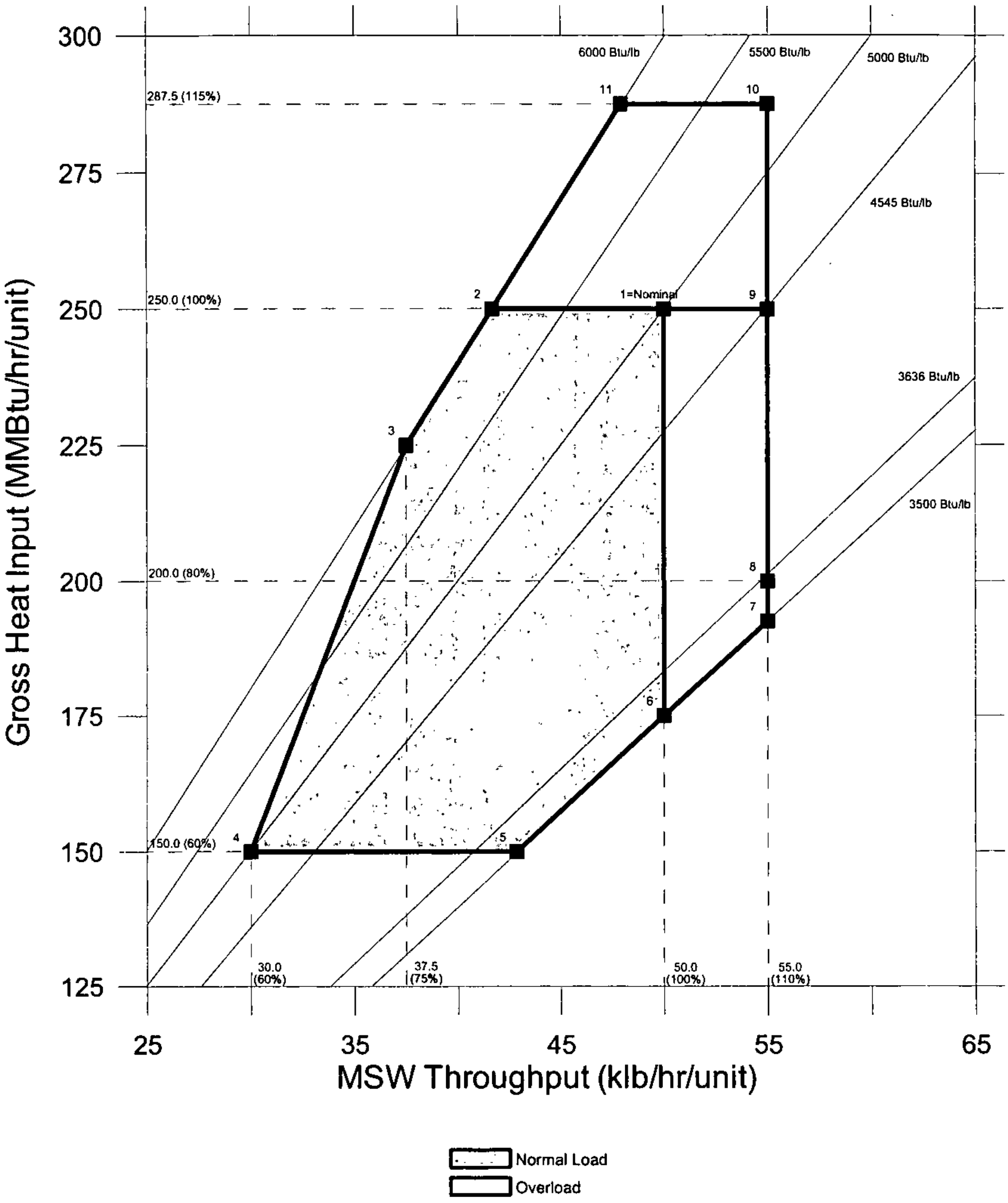
Operating Condition	Percent of Design Heat Input Rate	Waste Throughput (klbs/hr/unit)	Waste Heating Value (BTU/lb)	Heat Throughput (MMBTU/hr/unit)	Stack Gas Flow Rate (acfm)	Stack Gas Temp. (°F)
1	100	50.0	5,000	250.0	126,141	270°
2	100	41.7	6,000	250.0	125,421	270°
3	90	37.5	6,000	225.0	N/A	N/A
4	60	30.0	5,000	150.0	75,506	270°
5	60	42.9	3,500	150.0	76,258	270°
6	70	50.0	3,500	175.0	N/A	N/A
7	77	55.0	3,500	192.5	97,869	270°
8	80	55.0	3,636	200.0	N/A	N/A

Table 6-1 (Continued)
Municipal Waste Combustor
Unit 4 Operating Window & Stack Parameters

Operating Condition	Percent of Design Heat Input Rate	Waste Throughput (klbs/hr/unit)	Waste Heating Value (BTU/lb)	Heat Throughput (MMBTU/hr/unit)	Stack Gas Flow Rate (acfm)	Stack Gas Temp. (°F)
9	100	55.0	4,545	250.0	125,578	270°
10	115	55.0	5,227	287.5	145,149	270°
11	115	47.9	6,000	287.5	144,234	270°

From Brian Bahor, Covanta Projects, Inc. to Jason Gorrie, CDM, October 18, 2004.

Hillsborough County used merge plume rise for modeling of the existing three units plus the new Unit No. 4. The calculated equivalent stack diameters and flow rates for modeling of merged plumes are shown in **Table 6-2**.



CDM

Figure 6-4
Hillsborough County Resource
Recovery Facility
Unit 4 Stoker Capacity Diagram

Table 6-2
Municipal Waste Combustor
Existing Units' Stack Parameters

Units Simultaneously Firing	Stack Gas Flow Rate (acfm)	Equivalent Stack Diameter (m)	Stack Gas Exit Temperature. (°F)
1	88,868	1.65	289
2	177,736	2.19	289
3	266,604	2.68	289
4	411,647	3.65	282

Based on modeling performed for the Air Pollution Control Retrofit Preconstruction Permit Application prepared in September, 1997.

A second of screening modeling was conducted to ensure that the worst-case operating condition was identified for the combined facility. Three additional model runs were conducted to evaluate when Unit 4 is operating with one, two and three existing units simultaneously.

In addition, particulate matter would be emitted from the cooling tower, ash handling facility, and air pollution control equipment storage silos (pelletized and dolomite lime and activated carbon). However, the storage silos were considered insignificant sources of particulate matter; therefore, only the new cooling tower cell was included in the refined modeling analyses.

6.4.1 Good Engineering Practice (GEP) Stack Height Analysis and Building Downwash

Building downwash occurs when structures influence the plume from a nearby stack. The Good Engineering Practice (GEP) stack height is defined for each nearby structure or combination of nearby structures, as the structure height plus 1.5 times the lesser of the projected structure height or width. The U.S. EPA has created computer software to calculate GEP stack height and building downwash parameters to be used in dispersion modeling. The Building Profile Input Program (BPIP) accounts for the locations and heights of nearby structures with respect to point sources and determines the structure which exerts the most significant aerodynamic influence.

GEP analyses have been performed for this facility, showing that the existing 67 meter (220 feet) stack is within the area of influence of the main facility structure. The controlling structure or tier is the Boiler House with a tier height of 34 meters (111.5 feet). Thus, the calculated GEP stack height is 85 meters (279 feet). Therefore, the building downwash option was included in both the screening and refined modeling analyses.

The layout of the stack and buildings used in the GEP analysis are presented in **Figures 6-5** and **6-6**. The building tier heights are presented in **Table 6-3**.

Both the ISCST3 and CALPUFF dispersion models utilize the same 36 direction specific building parameters for downwash calculations. The SCREEN3 dispersion model uses the height, and the maximum and minimum projected widths of the dominant building for its downwash and cavity calculations. These values were taken from the output produced by BPIP.

PROJECT TITLE:

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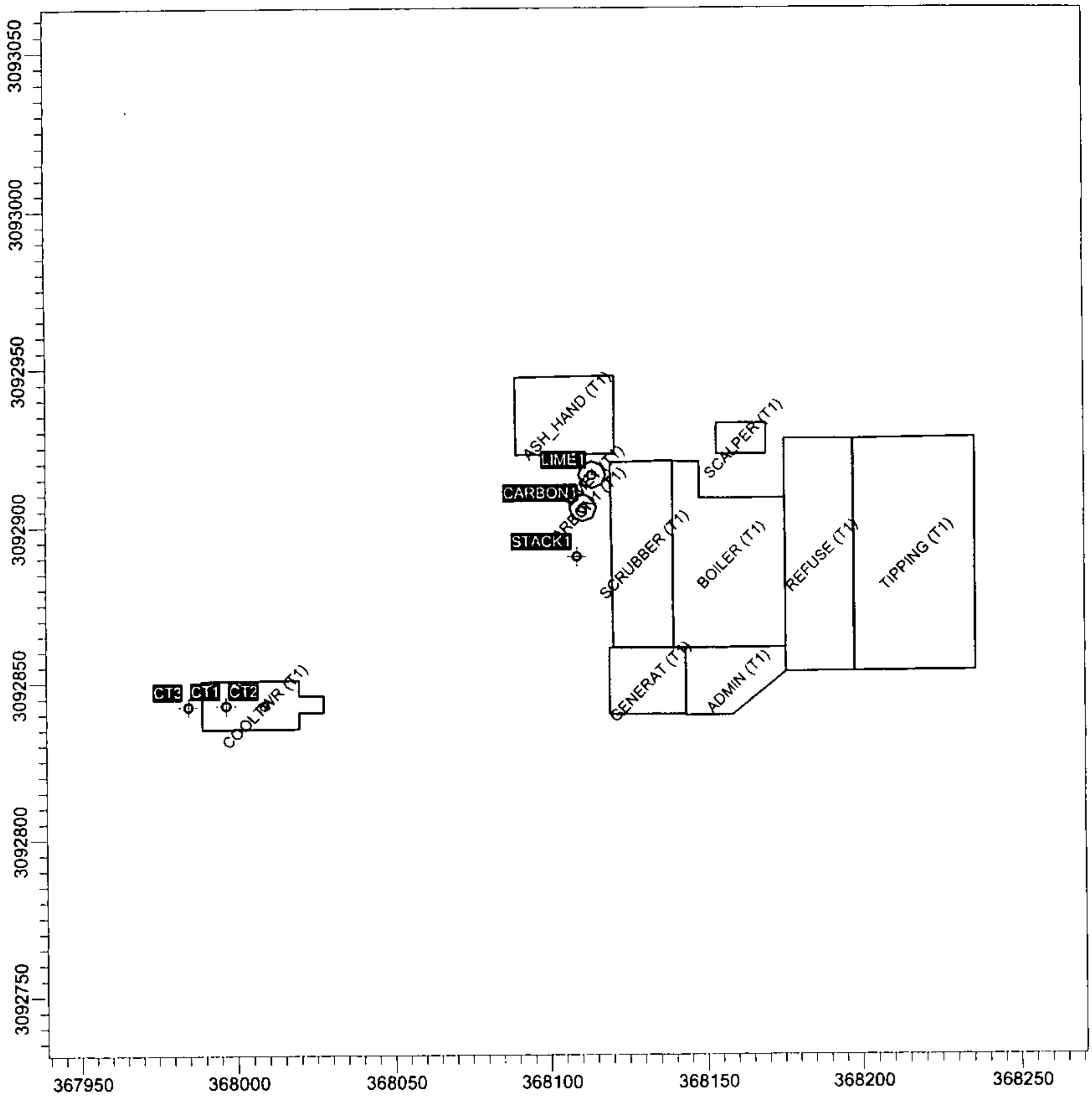
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS:

Figure 6-5

GEP Stack Height Analysis
Building Layout

BUILDINGS:

11

SOURCES:

6

COMPANY NAME:

CDM

MODELER:

Vincent R. Tino, CCM

0 0.05 km

CDM

DATE:

1/11/2005

PROJECT NO.:

6033-40441-FE.PSD.MODEL

BPIP View - Lakes Environmental Software

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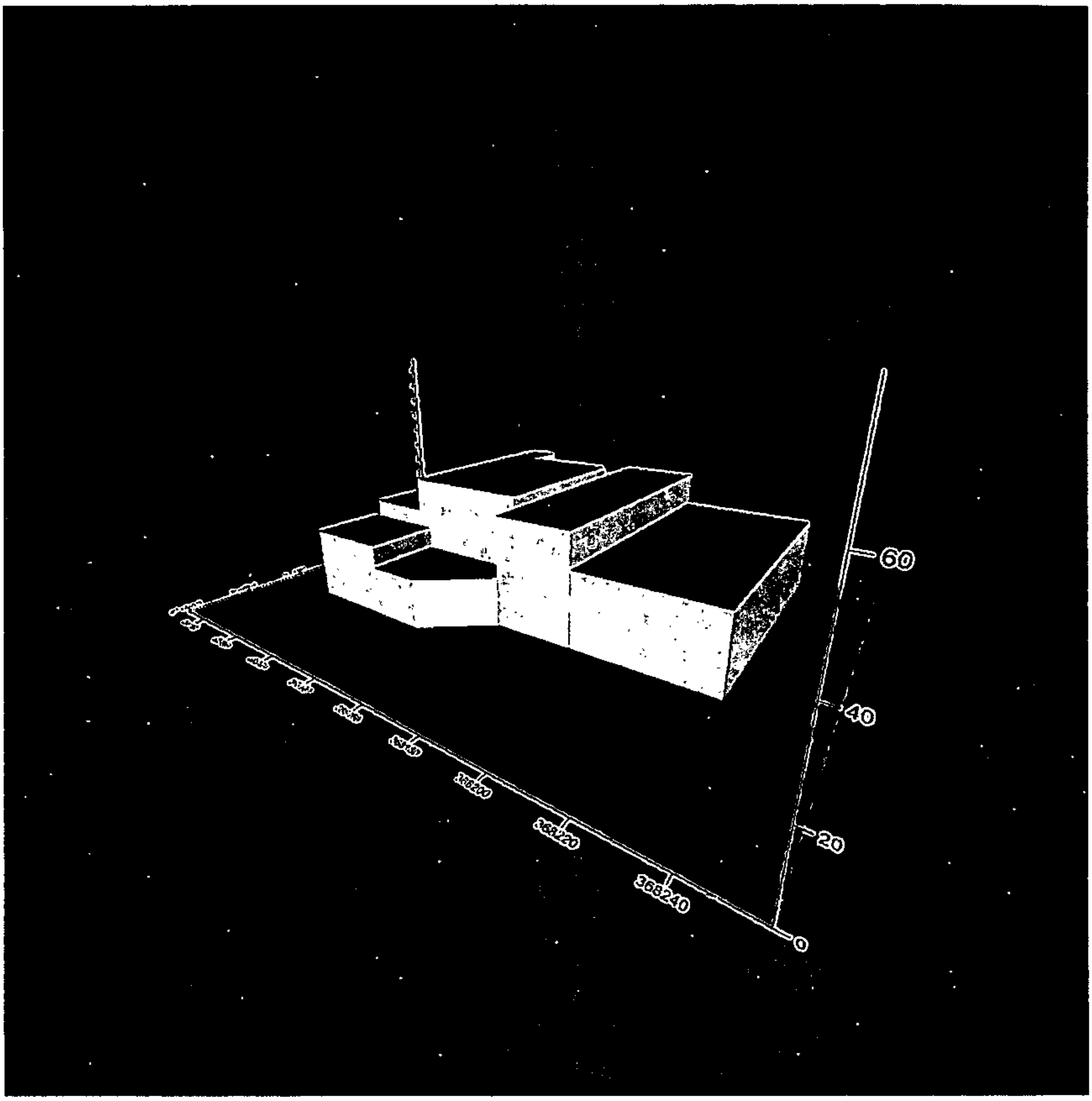
PROJECT TITLE:

Hillsboro County Solid Waste Energy Recovery Facility
Building Downwash & GEP Analysis



COMMENTS:

Figure 6-6

GEP Stack Height Analysis 3-D Building Layout

COMPANY NAME:

CDM

MODELER:

Vincent Tino

DATE:

7/29/2004

PROJECT NO.:

6033-40441-FE.PSD.MODEL

3D View - Lakes Environmental Software

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Table 6-3
BPIP Building Tiers and Heights

Tier Name	Roof Elevation (amsl)	Tier Height (m)
Ash handling	80 feet	12.5
Administration	84 feet	13.7
Refuse	140 feet	30.7
Tipping	108 feet	21.0
Scrubber	120 feet	24.7
Boiler/SCR	150 feet	34.0
Scalper	65 feet	7.9
Pelletized Lime Silo	108 feet	21
Dolomitic Lime Silo	82 feet	13
Activated Carbon Silo	101 feet	19
Cooling Tower	78 feet	12
Generator	105 feet	20

Ground elevation (amsl) is approximately 36-39 feet (11-12 meters).

6.5 Receptor Network

The screening analysis was performed solely to identify the worst facility operating condition. SCREEN3 allows the input of an automated distance array. The model accepts beginning and ending distances and automatically calculates downwind distances at discrete intervals. A beginning limit of 100 meters and an ending distance of 20 km was input. Flat terrain was assumed for this screening level analysis.

For the Class II refined modeling analyses, a Cartesian coordinate centered on the facility stack was used for the full modeling analysis to develop normalized pollutant concentration contour plots. The receptor grid spacing was 100 meters out to 10 kilometers. Since public access to the property is restricted, receptors located within plant boundaries were removed from the analysis. However, receptors were placed along the property boundary at a maximum spacing of 50 meters. A minimum of 1440 receptors were included in this grid.

It is U.S. EPA policy that major sources within 100 km of Class I areas show no significant adverse impacts to the Class I area. Sources at distances greater than 100 km may be required to show impacts if the reviewing agency deems that the proposed project "may affect" the Class I area. Receptors were placed in the Chassahowitzka Wildlife Refuge, located approximately 78 kilometers to the north-northwest of the facility. FDEP requires evaluating potential impacts to Class I areas located within 200 km of a facility. There are no formally designated Class I areas within 200 km of the Facility. The National Park Service has produced standard sets of receptors for Class I modeling analyses (National Park Service, 2004).

6.6 Meteorological Data

The SCREEN3 model used in the screening analysis contains 54 records of combinations of wind speed, Pasquill-Gifford stability class (A-F), and mixing height which are expected to produce the worst-case impacts from a source. Ten-meter wind speeds (u_{10}) range from 1 m/s to 20 m/s at varying increments. The six P-G stability classes are used, and mixing heights are set to $320u_{10}$. For stable conditions (E & F), mixing heights are set to 10,000 meters to represent unlimited mixing.

Meteorological data from the Tampa International Airport was used in the subsequent dispersion modeling analyses for Class II areas. The Tampa International Airport, approximately 6.7 miles (10.8 km) to the west of the Hillsborough County Facility, is the National Weather Service Station (WBAN Station No. 12842) closest to the site, and observed meteorological data is most representative of the site vicinity. Meteorological data needed for the ISCST3 model, and available from this station, include hourly readings of temperature, wind speed, wind direction, and total opaque cloud cover (atmospheric stability), as well as twice-daily measurements of upper air data used to calculate mixing heights. FDEP has provided most recent available five years of combined surface and upper air data (1991 through 1995) for use on this project. Because FDEP has already preprocessed these data (filling any data gaps), no further processing of this meteorological data was performed before using it in the ISCST3 model.

Although CALPUFF accepts meteorological data files in ISCST3 format, CALPUFF requires micrometeorological variables not present in the basic meteorological files used for ISCST3. Hourly values of friction velocity, Monin-Obukhov length, relative humidity, and solar radiation are not generally included in the ISCST3 format. However, CALPUFF is significantly more accurate when using gridded meteorological data fields produced by its meteorological preprocessor, CALMET. CALMET incorporates National Weather Service surface observations and sounding data, land use data, terrain data, and gridded mesoscale meteorological model (MM5) data to quantify hourly wind fields in both horizontal and vertical dimensions. According to discussions with the Division of Air Resource Management at the FDEP, CALPUFF with three years of CALMET/MM5 data is the requirement for long range/Class I areas. (Email Communication, Cleve Holladay, July 21, 2004). CDM obtained CALMET/MM5 data for 1990, 1992 and 1996 from FDEP. Since FDEP provided these data to the County, no additional preprocessing of these data was preformed prior to using them in CALPUFF.

6.7 Screening Modeling Results

The SCREEN3 model was run according to the aforementioned methodology. A unit emission rate (1 g/s) was used to produce normalized concentrations (μg/m^3 per g/s). An ambient atmospheric temperature of 293 K (68°F) was input. In addition, SCREEN3 utilizes basic building dimensions to account for downwash. A maximum building height of 34 meters, a maximum projected building width of 69.39 meters, and a minimum projected building width of 29.9 meters were input. The results of the screening-level modeling are presented in **Table 6-4**.

Table 6-4 shows that Unit 4 only Operating Condition 10 to be the worst-case scenario, with a maximum normalized concentration of 4.101 µg/m^3 at a downwind distance of 341 meters. The stack parameters associated with this operating condition were then used in all subsequent analyses. In addition, for each operating condition, concentrations predicted in the cavity region were set to 0.0 by the SCREEN3 model, since the calculated "critical wind speed" is greater than 20 m/s. The "critical wind speed" is defined as the wind speed that would calculate the plume centerline height equal to the calculated cavity height.

Screening modeling of Unit 4 plus the existing MWC units was conducted to determine which facility operating condition would generate the highest air quality impacts. The operating conditions evaluated were: one existing MWC unit plus Unit 4, two existing MWC units plus Unit 4, and all four units operating simultaneously. The results showed that all four units operating simultaneously produced the highest normalized concentration of 8.676 µg/m^3. Therefore, refined modeling was conducted for Unit 4 only and combined facility (all four units operating) based on the screening modeling results.

6.8 Refined and Class I Area Modeling Results

Since Unit 4 will be operating in addition to the existing units, additional modeling was performed to determine the maximum increase in facility impacts as well as maximum impacts due to the combined facility (all four units). The stack characteristics for the existing facility are presented in Table 6-2. Based on the initial screening analysis, it was determined that Operating Condition #10 produced the worst-case results. The stack airflow associated with Condition #10 (145,149 acfm) combined with a stack flue diameter of 2.261 meters produced an effective stack gas velocity of 17.061 m/s based on a gas exit temperature of 405.4 °K. CDM calculated the merged plume parameters for all four MWC units operating simultaneously to determine the combined facility impacts. The stack airflow associated with a merged plume (411,647 acfm) combined with a stack flue diameter of 3.65 meters produced an effective stack gas velocity of 18.60 m/s. based on a gas exit temperature of 412 °K. **Table 6-5** presents the source parameters for the Unit 4, and the combination of all four MWC and the existing and new cooling tower cells.

Air dispersion modeling was performed for both the entire facility and Unit 4 separately. In addition to estimating facility impacts due to emissions from both the existing and proposed MWC units, modeling analyses were also conducted to determine the maximum increase in facility impacts due to the proposed MWC unit. Operation of

Table 6-4
Municipal Waste Combustor
Screening Modeling Results

Operating Condition	Stack Gas Flow Rate (acfm)	Stack Gas Temp. (°F)	Emission Rate (g/s)	Maximum Normalized Concentration ($\mu g/m^3$)	Downwind Distance (m)
Unit 4 Only Operating Scenarios					
1	126,141	270 °	1.000	4.015	341
2	125,421	270 °	0.994	4.010	341
3	N/A	N/A	N/A	N/A	N/A
4	75,506	270 °	0.599	3.421	780
5	76,258	270 °	0.605	3.452	780
6	N/A	N/A	N/A	N/A	N/A
7	97,869	270 °	0.776	3.583	833
8	N/A	N/A	N/A	N/A	N/A
9	125,578	270 °	0.996	4.014	341
10	145,149	270 °	1.151	4.101	341
11	144,234	270 °	1.143	4.095	341
Existing Units + Unit 4 Operating Scenarios					
1 existing MWC Unit + Unit 4	234,048	277	2.291	6.128	341
2 existing MWC Units + Unit 4	322,956	281	3.431	7.235	340
3 existing MWC Units + Unit 4	411,647	282	4.571	8.676	340

Emissions for screening purposes are based on the ratio of the flow rate at each operating condition to the flow rate of the nominal condition (Operating Condition #1).

Table 6-5
Existing and New Sources Parameters

Source	Source Type	Release Height (m)	Exit Velocity (m/s)	Exit Temperature (K)	Effective Release Diameter (m)
MWC Unit 4 (new)	Point	67	17.1	405	2.26
All MWC Units (combined)	Point	67	18.6	412	3.65
Cooling Tower Cell 1	Point	12	5.4	Ambient	8.5
Cooling Tower Cell 2	Point	12	5.4	Ambient	8.5
Cooling Tower (new third cell)	Point	12	5.4	Ambient	8.5

Unit 4 by itself would be expected to cause the largest increase in facility impacts. This is because plume rise for the three existing units would be enhanced by the addition of Unit 4. As shown in **Table 6-6**, the Unit 4 normalized impacts do cause the largest increase in facility impacts compared to the combined facility. The predicted normalized impacts for Unit 4 only are presented in contour plots to illustrate their distribution in the vicinity of the site. **Figures 6-7** through **6-11** show the normalized impacts predicted for the Unit 4 only for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods, respectively. In each case, the distribution of impacts shown is based on the specific year in which the limiting impact (highest annual average concentration or H2H concentration) was predicted.

Table 6-6
Unit 4 and Facility
Normalized Modeled Concentrations

Averaging Period	Normalized Concentrations ((μg/m³)/(g/s))					
	1991	1992	1993	1994	1995	5-Year Max.
Unit 4 Only						
Annual High	0.04503	0.05214	0.04581	0.04329	0.04302	0.05214
1-hr High	3.30670	3.53275	3.64718	3.32593	3.73505	3.73505
1-hr H2H	3.18008	3.13700	3.13726	3.19354	3.29711	3.29711

Table 6-6 (Continued)
Unit 4 and Facility
Normalized Modeled Concentrations

3-hr High	2.47986	2.44592	2.25742	2.23077	2.17294	2.47986
3-hr H2H	1.84781	1.99205	2.10032	1.72497	1.86379	2.10032
8-hr High	1.24763	1.33067	1.69073	1.25488	1.34639	1.69073
8-hr H2H	1.06371	1.12710	1.42975	1.05430	1.25842	1.42975
24-hr High	0.75597	0.70088	0.82471	0.80766	0.90107	0.90107
24-hr H2H	0.71808	0.60740	0.74011	0.62872	0.63998	0.74011
Facility (All Four Units)						
Annual High	0.01330	0.01770	0.01689	0.01356	0.01601	0.01770
1-hr High	1.98608	1.81704	2.15003	1.70709	2.67502	2.67502
1-hr H2H	1.52931	1.48275	1.62699	1.52726	1.56978	1.62699
3-hr High	1.14726	1.13094	1.42083	1.10535	0.95236	1.42083
3-hr H2H	0.94700	0.95827	1.04287	0.97907	0.84827	1.04287
8-hr High	0.65028	0.64520	0.72848	0.76927	0.80462	0.80462
8-hr H2H	0.50707	0.54506	0.53921	0.52163	0.65455	0.65455
24-hr High	0.40452	0.32780	0.37082	0.46055	0.50634	0.50634
24-hr H2H	0.36625	0.28986	0.30509	0.27618	0.32284	0.36625

H2H = Highest, Second-Highest.

Unit 4 and combined facility emissions rates (in grams per second), presented in **Table 6-7**, were multiplied by the normalized concentrations, presented in Table 6-5, to calculate pollutant-specific concentrations for each averaging period as follows:

Pollutant Conc. (ug/m³) *= Normalized Conc. (ug/m³/g/s) x Poll. Emiss. Rate (g/s)*

The pollutant-specific concentrations were compared to applicable increments and standards discussed below.

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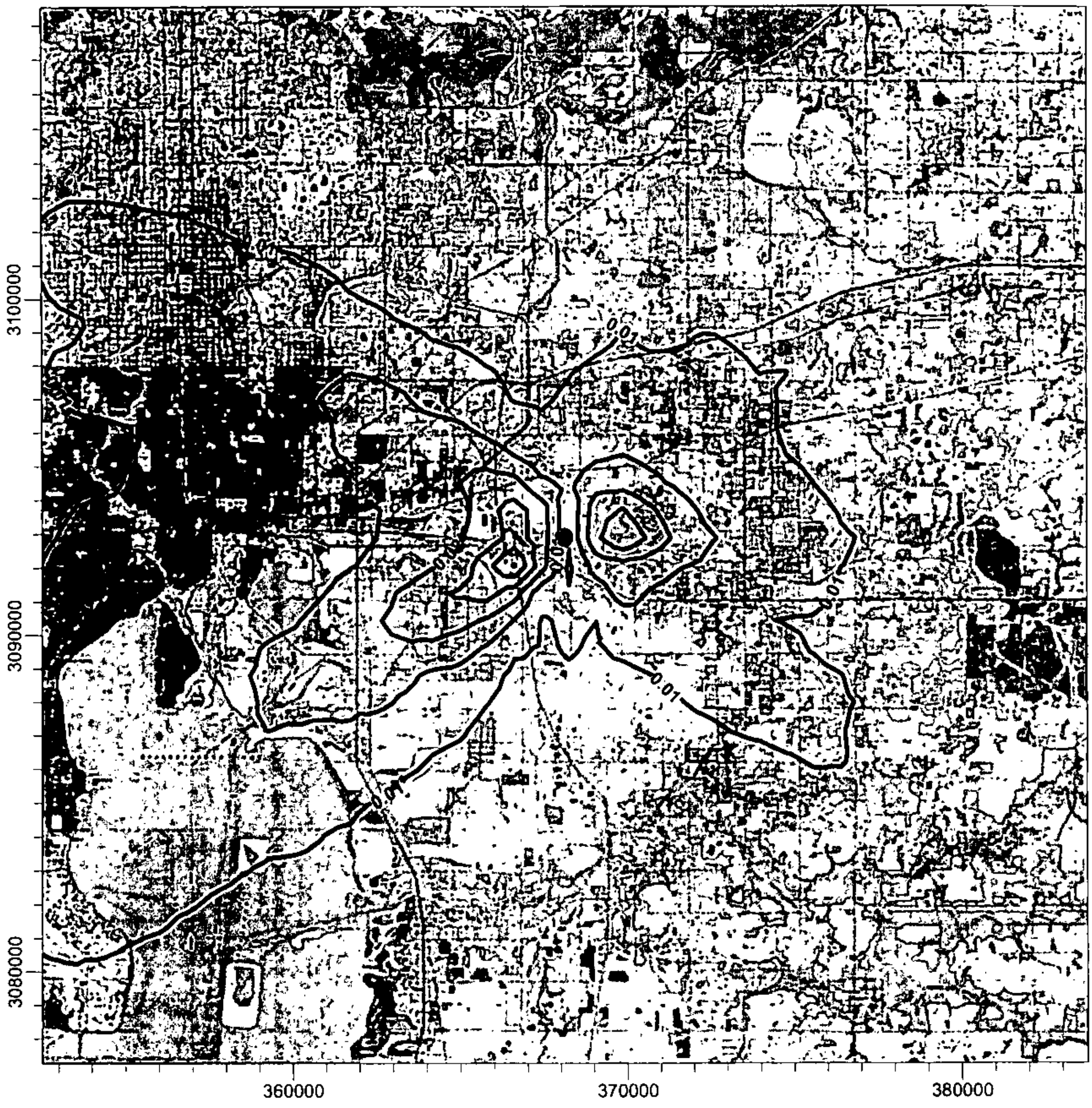

COMMENTS: **Figure 6-7** **Unit 4** **Maximum Annual** **Normalized Impacts**	MODELING OPTIONS: **CONC, RURAL, ELEV, HE>ZI**	COMPANY NAME: **CDM**	
	OUTPUT TYPE: **CONC** / RECEPTORS: **42150**	0 5 km	CDM
	MAX: **0.05945** / UNITS: **µg/m³**	DATE: **6/10/05**	PROJECT NO.:

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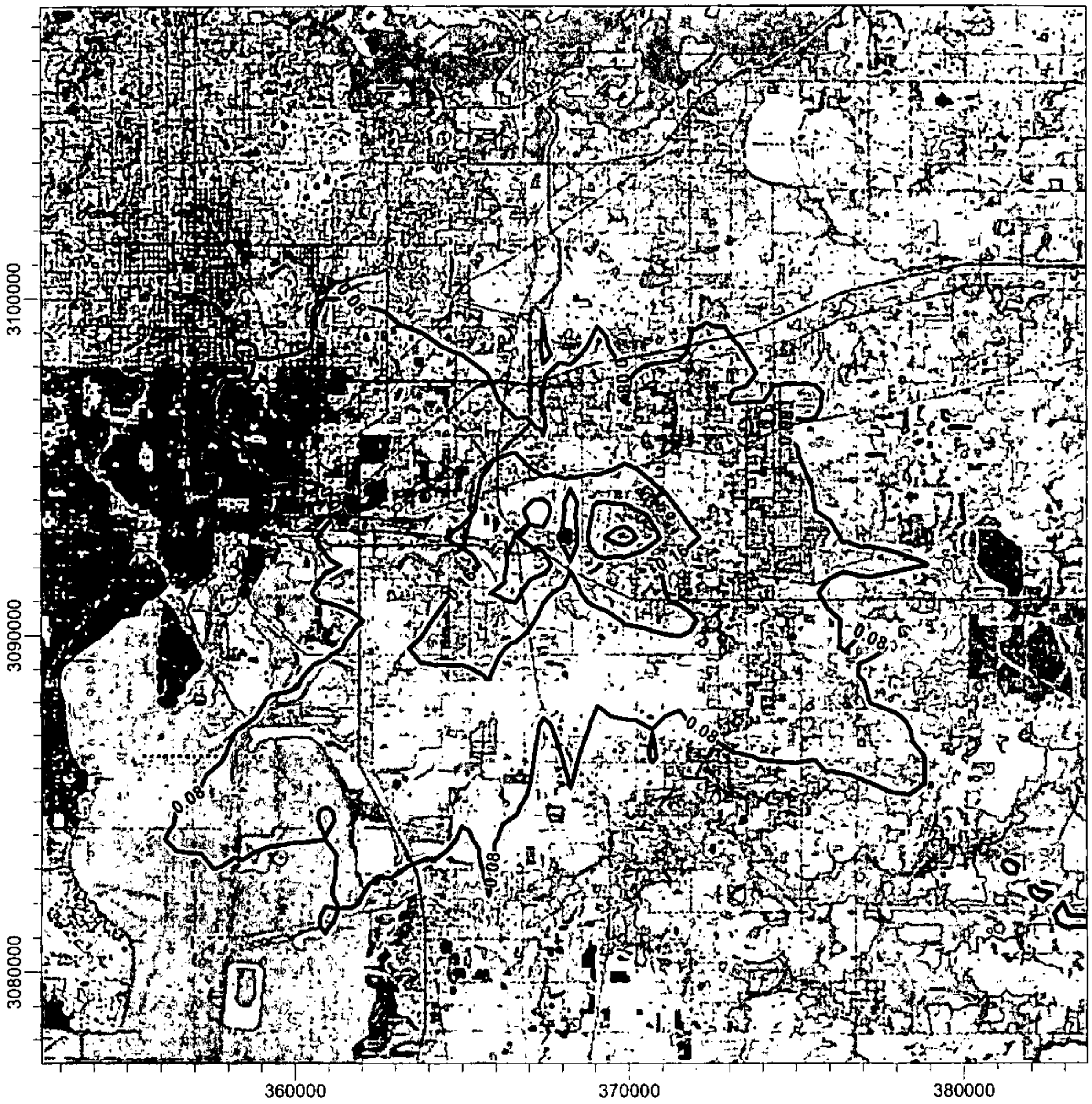
PROJECT TITLE:

Hillsborough County Resource Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS: **Figure 6-8** **Unit 4** **24-Hour High 2nd High** **Normalized Impacts**	MODELING OPTIONS: **CONC, RURAL, ELEV, HE>ZI**		COMPANY NAME: **CDM**
	OUTPUT TYPE: **CONC**	RECEPTORS: **42150**	0 5 km
	MAX: **0.7424**	UNITS: **µg/m³**	DATE: **6/10/05**
			PROJECT NO.:

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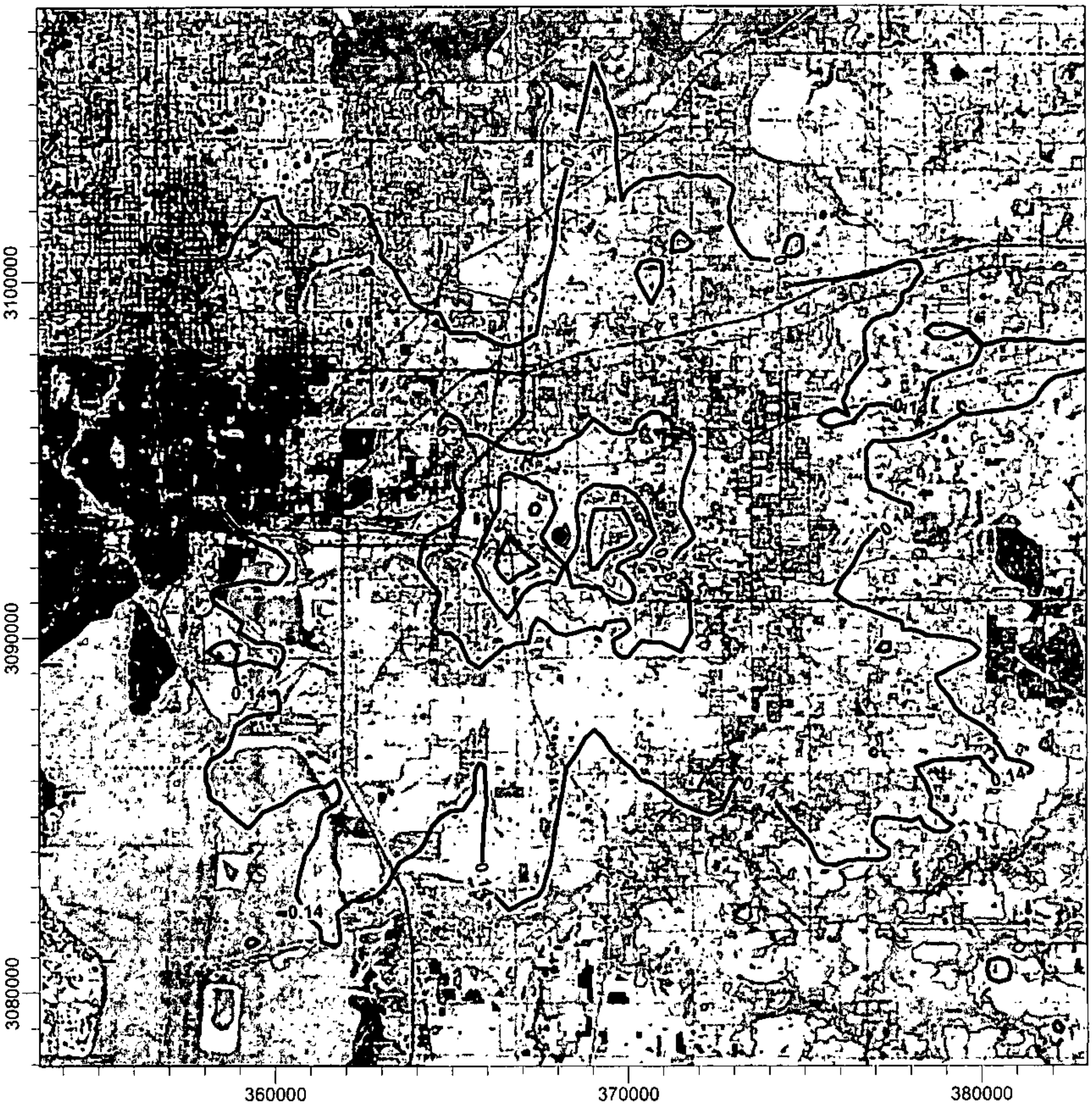
PROJECT TITLE:

Hillsborough County Resource Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS:

Figure 6-9
Unit 4
8-Hour High 2nd High
Normalized Impacts

MODELING OPTIONS:

CONC, RURAL, ELEV, HE>ZI

COMPANY NAME:

CDM

OUTPUT TYPE:	RECEPTORS:
CONC	**42150**

0 5 km

MAX:	UNITS:	DATE:	PROJECT NO.:
1.25842	**µg/m³**	**6/10/05**	

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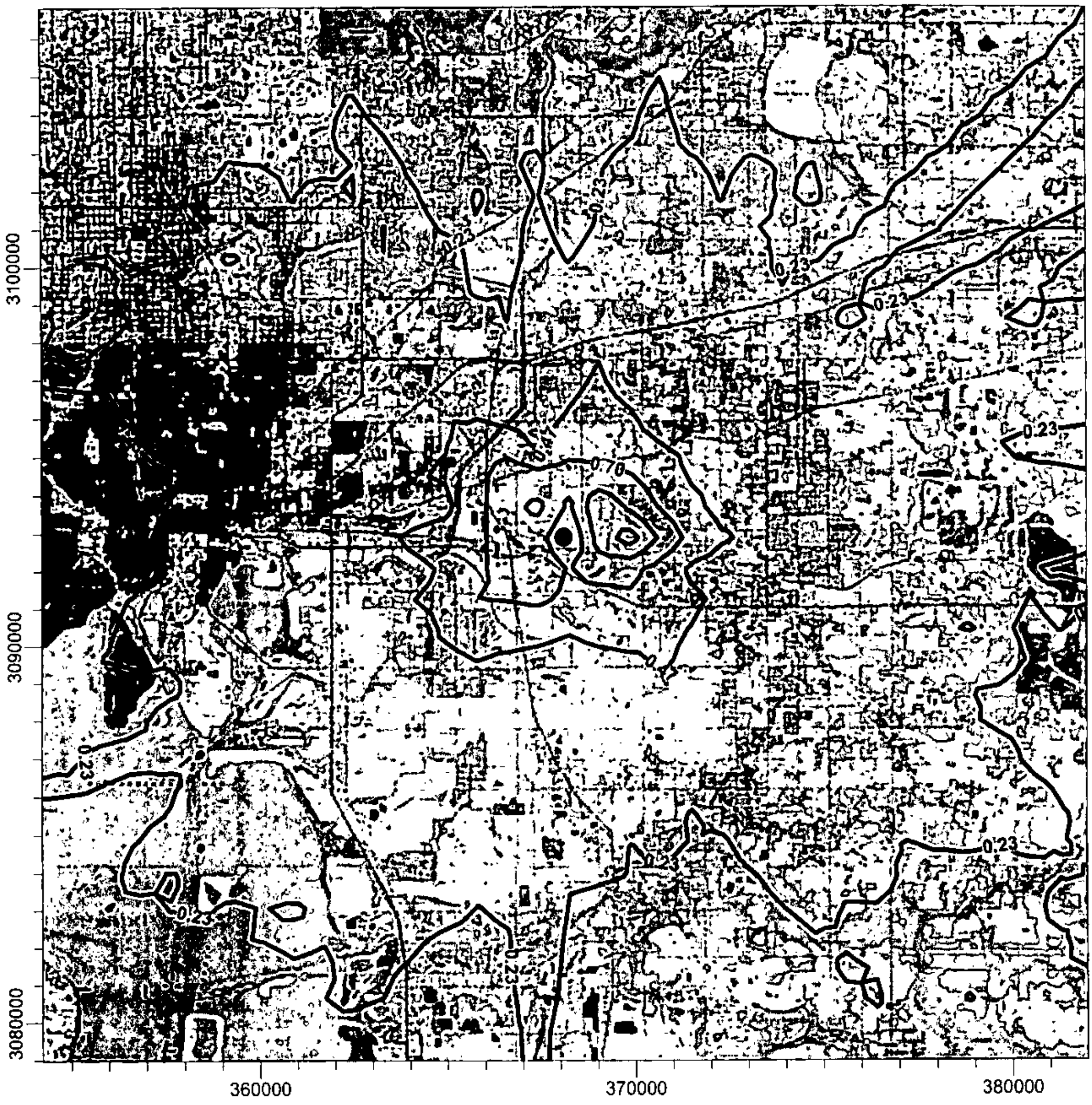
PROJECT TITLE:

Hillsborough County Resource Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS: **Figure 6-10** **Unit 4** **3-Hour High 2nd High** **Normalized Impacts**	MODELING OPTIONS: **CONC, RURAL, ELEV, HE>ZI**		COMPANY NAME: **CDM**
	OUTPUT TYPE: **CONC**	RECEPTORS: **42150**	0 — 5 km
	MAX: **2.10032**	UNITS: **µg/m³**	DATE: **6/10/05**
			PROJECT NO.:

CDM

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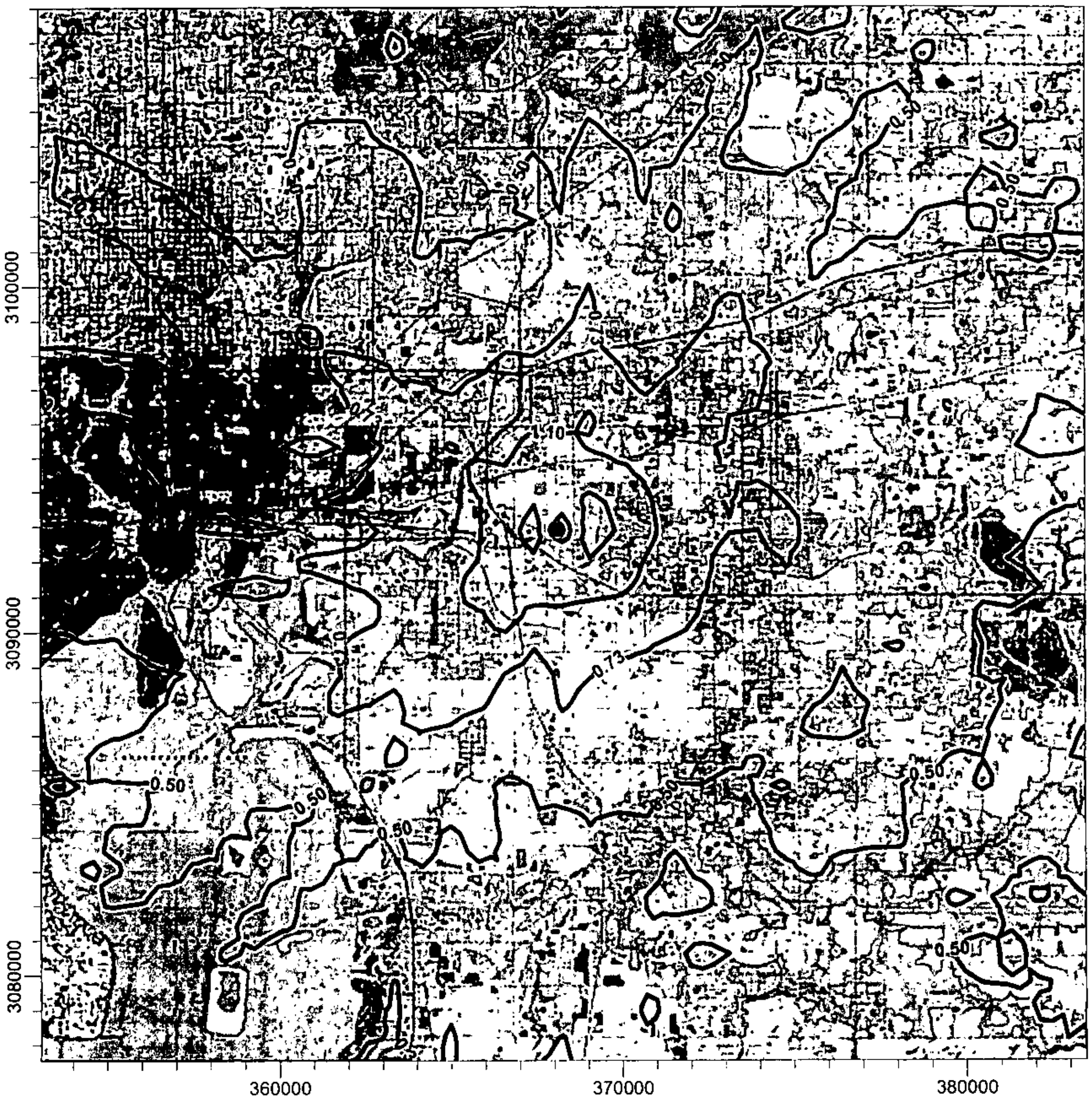
PROJECT TITLE:

Hillsborough County Resource Recovery Facility
Unit 4 Prevention of Significant Deterioration Permit Application



COMMENTS:

Figure 6-11
1-Hour High 2nd High
Normalized Impacts

MODELING OPTIONS:

CONC, RURAL, ELEV, HE>ZI

COMPANY NAME:

CDM

OUTPUT TYPE:

CONC

RECEPTORS:

42150

0 ——— 5 km

MAX:

3.29711

UNITS:

µg/m³

DATE:

6/10/05

PROJECT NO.:

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6.8.1 Significant Impact Levels and De Minimis Monitoring Levels

Maximum increases in facility impacts due to Unit 4 are compared to the Class II Significant Impact Levels (SILs) in **Table 6-8**. Maximum impacts due to Unit 4 are less than Class II SILs for all criteria pollutants (SO_2, NO_x, CO, PM_{10} and Pb). Impacts are less than 25 percent of the SILs for CO, PM_{10} and Pb, 44 percent of less of the SILs for SO_2 and 38 percent of the SIL for NO_x. SILs are concentrations below which a facility would not be considered to cause or contribute to a violation of the NAAQS (40 CFR 51,165(b)(2)). For pollutant/averaging periods with predicted impacts below the SIL, no further analysis is required.

Table 6-7
Existing Facility and Unit 4 Modeling Emissions Rates

Pollutant	**Emission Rates (g/s)**				
	Existing Facility			**New**	
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Total**
Sulfur Dioxide (SO_2)	4.14	4.14	4.14	2.42	14.85
Nitrogen Oxides (NO_x)	7.39	7.39	7.39	7.37	29.53
Carbon Monoxide (CO)	2.19	2.19	2.19	3.26	9.84
Particulate Matter (PM)	0.52	0.52	0.52	0.72	2.27
Dioxin	5.67E-07	5.67E-07	5.67E-07	4.55E-07	2.16E-06
Mercury (Hg)	2.52E-03	2.52E-03	2.52E-03	4.67E-03	1.22E-02
Cadmium (Cd)	7.56E-04	7.56E-04	7.56E-04	7.00E-04	2.97E-03
Lead (Pb)	8.19E-03	8.19E-03	8.19E-03	7.00E-03	3.16E-02
Hydrogen Chloride (HCl)	2.14	2.14	2.14	3.20	9.62
Hydrogen Fluoride (HF)	0.13	0.13	0.13	0.10	0.48
Volatile Organic Compounds (VOCs)	--	--	--	2.14	2.14
Sulfuric Acid Mist (SAM)	--	--	--	0.72	0.72
Metals (as PM)	--	--	--	1.24	1.24
Ammonia (NH_3)	--	--	--	1.90	14.32

Table 6-8 Unit 4 Only Comparison of Unit 4 Only Maximum Impacts to SILs								
	Unit 4 Maximum Impacts (ug/m^3)							
Pollutant	**1991**	**1992**	**1993**	**1994**	**1995**	**5-Year Max.**	**SIL (ug/m^3)**	**Percent of SIL**
NO_x Annual	0.33	0.38	0.34	0.32	0.32	0.38	1	38%
CO 1-hr	10.79	11.52	11.90	10.85	12.18	12.18	2000	1%
CO 8-hr	4.07	4.34	5.51	4.09	4.39	5.51	500	1%
SO_2 3-hr	6.01	5.93	5.47	5.41	5.27	6.01	25	24%
SO_2 24-hr	1.83	1.70	2.00	1.96	2.18	2.18	5	44%
SO_2 Annual	0.109	0.13	0.11	0.10	0.10	0.13	1	13%
PM_{10} 24-hr	0.60	0.53	0.46	0.68	0.72	0.72	5	14%
PM_{10} Annual	0.24	0.06	0.05	0.06	0.06	0.24	1	24%
Pb Quarter	0.005	0.005	0.006	0.006	0.006	0.006	0.03	21%

The maximum 24-hour modeled concentrations were used to conservatively determine compliance with quarterly value.

The purpose of comparing facility impacts to de minimis monitoring levels is to determine if ambient air quality monitoring will be required to define background air quality prior to submitting the air permit application. A proposed facility that is considered a major source under the PSD regulations is required to evaluate ambient air quality levels in the vicinity of the facility. Maximum increases in facility impacts due to Unit 4 are compared to de minimis monitoring levels in **Table 6-9**. Maximum impacts due to Unit 4 are less than the de minimis monitoring levels for all pollutants. Therefore, the County is requesting that Unit 4 be exempt from preconstruction ambient monitoring under the PSD regulations.

Table 6-9
Comparison of Unit 4 Maximum Impacts to De Minimis Monitoring Levels

Pollutant	Unit 4 Maximum Conc. (ug/m^3)	Percent of De Minimis	De Minimis Monitoring Level (ug/m^3)
NO_x Annual	0.38	2.74%	14
CO 8-hr	5.51	0.96%	575
SO_2 24-hr	2.18	16.80%	13
PM_{10} 24-hr	0.72	7.15%	10
Lead (Pb)	6.31E-03	6.31%	0.1
Mercury (Hg) 24-hr	4.21E-03	1.68%	0.25
Hydrogen Flouride (HF) 24-hr	0.09	36.75%	0.25
Vinyl Chloride (VC) 24-hr	No Emissions are Expected from Existing or Proposed Units		15
Total Reduced Sulfur (TRS) 1 -hr	No Emissions are Expected from Existing or Proposed Units		10
Reduced Sulfur Compounds 1-hr	No Emissions are Expected from Existing or Proposed Units		10
Hydrogen Sulfide (H_2S) 1-hr	No Emissions are Expected from Existing or Proposed Units		0.2

6.8.2 PSD Increment Analysis Results

As part of the 1977 Clean Air Act (CAA) amendments established PSD in attainment areas. Attainment areas are put into one of three classes and the amount of deterioration allowed is determined by the class. Class I areas include National Parks and Wilderness Areas, and almost no increase in pollution is allowed. Moderate deterioration is allowed in Class II areas, and even greater amounts are allowed in Class III areas. However, no Class III areas have been designated in the United States. Therefore, the remainder of the United States, including the project area is defined as a Class II area.

There is only one formally designated Class I areas (40 CFR 52.21(e)) within 200 km of the Facility (http://www2.nature.nps.gov/air/maps/index.htm). The Chassahowitzka National Wildlife Refuge, about 78 km from the Facility, is the closest Class I area. This location was included in the Class I area evaluation.

Presented below are the results of modeling analysis for both the Class II and Class I areas.

Class II Area

The modeling analysis demonstrated that NO_x, SO_2 and PM_{10} emissions from Unit 4 and the combined facility resulted in concentrations less than the PSD Class II increments. As a major source of NO_x, SO_2 and PM_{10}, the Unit 4 and the combined Facility were considered to consume PSD increment for the pollutant-specific averaging periods presented in **Table 6-10**. The PSD increments established the maximum allowable increase in pollutant concentrations above some assumed baseline level.

The refined modeling analyses showed that no PSD Class II increments would be exceeded for either Unit 4 or the combined facility. Unit 4 maximum impacts consumes less than 2 percent of its PSD Class II increment for each pollutant, and the combined facility maximum impacts are less than 12 percent of the same increment for each pollutant. Therefore, pollutant impacts for all four MWC units represent only a small percentage of the total Class II PSD increments in the project area.

Table 6-10
Comparison of Unit 4 and Facility Maximum Impacts to PSD Class II Increments

Pollutant	Unit 4 Max. Conc. (ug/m^3)	Percent of Class II	Facility Max. Conc. (ug/m^3)	Percent of Class II	PSD Class II Increment (ug/m^3)
Annual NO_x	0.38	1.54%	0.52	2.09%	25
3-hr SO_2	5.09	0.99%	15.48	3.02%	512
24-hr SO_2	1.79	1.97%	5.44	5.97%	91
Annual SO_2	0.13	0.63%	0.26	1.31%	20
24-hr PM_{10}	0.58	1.94%	3.49	11.62%	30
Annual PM_{10}	0.24	1.41%	0.70	4.12%	17

Class I Area

The results of the refined modeling analysis for the Chassahowitzka National Wildlife Refuge were compared to the National Park Services (NPS) SILs and PSD Class I increments, as shown in **Table 6-11**. Maximum concentrations for Unit 4 are predicted not to exceed the NPS SILs or the PSD Class I increments for each pollutant. Therefore, no additional analyses were required.

6.8.3 National Ambient Air Quality Standards

Although a cumulative impact analysis is not required for this project, total predicted project impacts for both Unit 4 and the combined facility were compared to NAAQS for informational purposes.

Table 6-11
Comparison of Maximum Class I Impacts to Significant Impact Levels and PSD Increments

Pollutant	Unit 4 Max. Conc. (ug/m^3)	NPS Class I SILs (ug/m^3)	Percent of Class I	PSD Class I Increment (ug/m^3)	Percent of Class I
Annual NO_x	**2.68E-03**	0.03	8.94%	2.5	0.11%
3-hr SO_2	**1.23E-01**	0.48	25.57%	25	0.49%
24-hr SO_2	**3.02E-02**	0.07	43.07%	5	0.60%
Annual SO_2	**1.81E-03**	0.03	6.05%	2	0.09%
24-hr PM_{10}	**9.00E-03**	0.27	3.33%	8	0.11%
Annual PM_{10}	**6.47E-04**	0.08	0.81%	4	0.016%

NAAQS have been established by EPA at two levels: primary and secondary. Primary standards are required to be set at levels that will protect public health and include an "adequate margin of safety." Secondary standards are meant to be more stringent than primary standards. Secondary standards are established to protect public welfare (e.g., structures, crops, animals, etc.). The purpose of this analysis is to demonstrate that the proposed Unit 4 and the combined Facility will not cause or contribute to an exceedance of an AAQS. Where Unit 4 did not exceed an SIL for a given pollutant, compliance with an AAQS is demonstrated by adding Unit 4 impact to the ambient background concentration for that pollutant and averaging period. Similarly, the combined Facility impacts were added to the ambient background concentration and compared to the AAQS to determine compliance.

The short-term and maximum annual impacts from Unit 4 and the Combined Facility were compared to the NAAQS in **Table 6-12**. Maximum concentrations from Unit 4 are less than 1 percent of the AAQS and when added to ambient background levels determined in Section 5, it is still in compliance with NAAQS by a significant margin. Unit 4 maximum impacts plus background levels range from 19 percent (SO_2 annual) to 73 percent (PM_{10} 24 -hour). Similarly, the maximum concentrations from the combined facility impacts are less than 3 percent of the NAAQS and when added to ambient background levels, the combined facility impacts are well below the NAAQS. Combined facility maximum impacts plus background levels range from 19 percent (SO_2 annual) to 75 percent (PM_{10} 24 -hour). Therefore, no NAAQS are at risk of exceeding their applicable NAAQS. As discussed above, Unit 4 maximum impacts are less than the SILs in all Class II areas. Therefore, the Unit 4 and the combined facility will not cause NAAQS violations.

6.8.4 Ambient Reference Concentrations

The Florida Air Toxics Working Group developed a list of Ambient Reference Concentrations (ARCs) for a number of non-criteria pollutants. However, as of March 1, 2000, FDEP ruled that the ARCs are not rules nor do they implement any statutory authority (March 1, 2000 DARM-PER-28). Nonetheless, the ARCs are still useful in evaluating the magnitude of non-criteria pollutant impacts. **Table 6-13** compares both Unit 4 and the combined facility non-criteria pollutant impacts to the applicable ARC.

Table 6-12
Comparison of Unit 4 and Combined Facility
Maximum Impacts to NAAQS

		Unit 4/Combined Facility Maximum Impacts (ug/m^3)									
Pollutant	**Baseline (ug/m^3)**	**1991**	**1992**	**1993**	**1994**	**1995**	**Max. Conc.**	**Percent of AAQS**	**Background+ Unit 4 /Facility (ug/m^3)**	**Percent of AAQS**	**AAQS (ug/m^3)**
Unit 4 Only											
NO_x Annual	21	0.33	0.38	0.34	0.32	0.32	**0.38**	0.38%	**21.38**	21.38%	100
CO 1-hr	8,360	10.37	10.23	10.23	10.42	10.75	**10.75**	0.03%	**8,371**	20.93%	40,000
CO 8-hr	5,153	3.47	3.68	4.66	3.44	4.10	**4.66**	0.05%	**5,158**	51.58%	10,000
SO_2 3-hr	317	3.52	3.79	4.00	3.28	3.55	**4.00**	0.31%	**321.00**	24.69%	1,300
SO2 24-hr	61	1.37	1.16	1.41	1.20	1.22	**1.41**	0.54%	**62.41**	24.00%	260
SO_2 Annual	11	0.09	0.10	0.09	0.08	0.08	**0.10**	0.17%	**11.10**	18.50%	60
PM_{10} 24-hr	109	--	--	--	--	--	**0.58**	0.39%	**109.58**	73.06%	150
PM_{10} Annual	29	0.24	0.06	0.05	0.06	0.06	**0.24**	0.48%	**29.24**	58.48%	50
Lead (Pb)	0.47	5.03E-03	4.25E-03	5.18E-03	4.40E-03	4.48E-03	**5.18E-03**	0.35%	**0.48**	31.68%	1.5
Combined Facility (All Four Units)											
NO_x Annual	21	0.39	0.52	0.50	0.40	0.47	**0.52**	0.52%	**21.52**	21.52%	100
CO 1-hr	8,360	15.05	14.59	16.01	15.03	15.44	**16.01**	0.04%	**8,376**	20.94%	40,000
CO 8-hr	5,153	4.99	5.36	5.31	5.13	6.44	**6.44**	0.06%	**5,160**	51.60%	10,000
SO_2 3-hr	317	13.56	13.73	14.94	14.02	12.15	**14.94**	1.15%	**331.94**	25.53%	1,300
SO2 24-hr	61	5.25	4.15	4.37	3.96	4.62	**5.25**	2.02%	**66.25**	25.48%	260
SO_2 Annual	11	0.19	0.25	0.24	0.19	0.23	**0.25**	0.42%	**11.25**	18.76%	60
PM_{10} 24-hr	109	--	--	--	--	--	**3.49**	2.32%	**112.49**	74.99%	150
PM_{10} Annual	29	0.70	0.22	0.21	0.24	0.25	**0.70**	1.40%	**29.70**	59.40%	50
Lead (Pb)	0.47	0.01	0.01	0.01	0.01	0.01	**0.012**	0.77%	**0.48**	32.10%	1.5

The P_{10} 24-hour maximum impacts for both Unit 4 and combined facility are based on the highest-sixth highest concentration over five years.

Maximum impacts from Unit 4 for all pollutants are less than 37 percent of the ARC, except for SAM, which is at about 80 percent of the 24-hour ARC. The combined facility maximum impacts for all pollutants are well below ARC, except for SAM. The SAM concentration for both Unit 4 and combined facility are the same because there were no SAM emissions projected for the existing MWC units. Because the ARCs are based on conservative safety factors to protect public health, the refined modeling results for both Unit 4 and the combined facility demonstrate there would be no significant impact to human health. A more detailed human health and ecological risk assessment is contained in the Power Plant Siting Act (PPSA) application for Unit 4.

Table 6-13
Comparison of Unit 4 and Facility Maximum Impacts to Ambient Reference Concentrations[1]

Pollutant	Unit 4 Max. Conc. (ug/m^3)	Percent of ARC	Facility Max. Conc. (ug/m^3)	Percent of ARC	ARCs (ug/m^3)
HCl 8-hr	5.40	7.7%	7.74	11.1%	70
HCl 24-hr	2.88	16.9%	4.87	28.7%	17
HCl Annual	0.17	2.4%	0.17	2.4%	7
Cd 8-hr	1.18E-03	5.9%	2.39E-03	11.9%	0.02
Cd 24-hr	6.31E-04	12.6%	1.50E-03	30.1%	5.00E-03
Cd Annual	3.65E-05	6.5%	5.25E-05	9.4%	5.60E-04
Pb 8-hr	1.18E-02	2.4%	2.54E-02	5.1%	0.5
Pb 24-hr	6.31E-03	6.3%	1.60E-02	16.0%	0.1
Pb Annual	3.65E-04	0.4%	5.59E-04	0.6%	0.09
Hg 8-hr	7.90E-03	7.90%	9.84E-03	9.8%	0.1
Hg 24-hr	4.21E-03	21.1%	6.19E-03	31.0%	0.02
Hg Annual	2.44E-04	0.08%	2.17E-04	0.07%	0.3
Dioxin Annual[2]	2.37E-08	2.0%	3.82E-08	3.2%	1.21E-06
HF 8-hr	0.17	0.66%	0.39	1.5%	26
HF 24-hr	0.09	1.5%	0.24	3.9%	6.2
SAM 8-hr	3.62	36.2%	3.62	36.2%	10
SAM 24-hr	1.93	80.4%	1.93	80.4%	2.4
NH_3 8-hr	2.09	1.23%	2.09	1.23%	170
NH_3 24-hr	1.11	2.7%	1.11	2.7%	41
NH_3 Annual	0.06	0.06%	0.06	0.06%	100

Notes:
[1] FDEP, June 1995, Working List of "Ambient Reference Concentrations" for Hazardous Air Pollutants, Version 4.0.
[2] The ARC for dioxin is expressed as toxic equivalent 2,3,7,8-TCDD. Because the impacts analysis for total dioxins and furans, the ARC was converted to total dioxins and furans by multiplying by 55. The conversion factor is from 60 FR 65395, December 19, 1995, Table 1.

Notes:

[1] FDEP, June 1995, Working List of "Ambient Reference Concentrations" for Hazardous Air Pollutants, Version 4.0.

[2] The ARC for dioxin is expressed as toxic equivalent 2,3,7,8-TCDD. Because the impacts analysis for total dioxins and furans, the ARC was converted to total dioxins and furans by multiplying by 55. The conversion factor is from 60 FR 65395, December 19, 1995, Table 1.

Section 7
Additional Impact Analysis

This section describes the analysis performed to assess the impact of the addition of a fourth MWC unit (herein referred to as Unit 4) at the Hillsborough County Resource Recovery Facility (Facility) on air quality related values (AQRVs) for nearby Class I areas, as required under the Prevention of Significant Deterioration (PSD) regulations. The values assessed are:

- Visibility in Class I areas within 100 km of The Facility or as advised by Florida Department of Environmental Protection (FDEP);
- Impacts from growth indirectly related to Unit 4; and
- The potential for impacts to soil and vegetation.

The Chassahowitzka Wildlife Refuge is the closest Class I area, located approximately 78 km from the Facility, therefore, additional Class I impact analyses were required.

Because the sensitive areas are over 50 kilometers from the source, U.S. Environmental Protection Agency (EPA) guidance recommends the use of the CALPUFF model to analyze concentrations, visibility and deposition impacts (40 Code of Federal Regulations (CFR) 51, Appendix W, Guideline on Air Quality Models). Modeling parameters as described in Section 6.2.3 were used for the analyses. The most recent available version of CALPUFF (currently Version 5.7 dated 030402) was used to assess deposition and visibility impacts in the Chassahowitzka Wildlife Refuge. The ISCST3 input files were converted to CALPUFF input files using the ISC2PUF program, and were run with three years of CALMET/MM5 meteorological data (1990, 1992 and 1996) obtained from FDEP. The CALPOST and POSTUTIL programs were used to extract the required deposition and visibility information from the hourly binary concentration file produced by CALPUFF. The CALPUFF post-processor, CALPOST, was used to calculate haze/visibility parameters as well as convert deposition flux to kg/(hectare*year).

7.1 Visibility

Visibility impairment can be quantified by determining the spectral light intensity at a given location in the atmosphere with known aerosol and pollutant concentrations. Visibility impairment includes such things as the reduction of visual range, the perceptibility of plume shapes and haze layers, atmospheric discoloration, and plume-modified visual contrast of distant objects. These effects are caused by changes in light intensity as a result of the scattering and absorption of light (radiation) by particles and/or atmospheric aerosols. When the physical and chemical properties of the plume are known, the impact on visibility can be estimated (Latimer and Ireason, 1980).

Calculation of impacts to visibility are only required at Class I areas. Per the National Park Service (NPS) guidance, the CALPUFF model was used to assess visibility impacts at the Chassahowitzka Wildlife Refuge using methods outlined by IWAQM (EPA 1998). However, a visibility analysis was also conducted for sensitive Class II areas within 100 km of the Facility for informational purposes only. CDM identified 30 sensitive Class II areas designated under the Florida Scenic Highways Program, Florida State Parks, and the Florida Fish and Wildlife Refuges (CDM, 2005).

CALPUFF was used to predict concentrations of sulfates and nitrates. Resulting concentrations of $SO_4^{=}$, NO_3^{-}, and HNO_3 were used to calculate 24-hour averaged extinction coefficients and compute the percent change in extinction. The light extinction coefficient includes both scattering and absorption components, and is a measure of light attenuation over a unit distance.

CALPUFF was set to create concentration data files that were used as input files for the CALPOST post-processor. Parameters used in the CALPOST post-processor are listed below:

- Modeled Species: Sulfates and Nitrates
- Computation Method: Compute extinction from speciated PM measurements (CALPOST, Method 2).
    - RH adjustment applied to observed and modeled sulfate and nitrate
    - RH factor is capped at Maximum Relative Humidity (RHMAX).
- RHMAX: 95%
- Extinction Efficiency:
    - Ammonium Sulfate: 3 Mm^{-1} per $\mu g/m^3$
    - Ammonium Nitrate: 3 Mm^{-1} per $\mu g/m^3$
- Background concentration for computing background extinction coefficients
    - Ammonium Sulfate: 0.2 $\mu g/m^3$
    - Ammonium Nitrate: 0.1 $\mu g/m^3$
    - Soil: 0.5 $\mu g/m^3$
    - Coarse Particulates: 3.0 $\mu g/m^3$
- Extinction due to Rayleigh Scattering: 22.0 Mm^{-1}
- Averaging time: 24-hour
- Visibility units: Mm^{-1}

Natural background estimates for the visibility reference level at the Chassahowitzka Wildlife Refuge were obtained from information in the Federal Land Managers' Air Quality Related Values Workgroup (FLAG), guidance, December 2000.

In accordance with guidance, the change in the 24-hour light extinction was predicted to be slightly above 5 percent (5.4 percent) when compared to natural conditions. The predicted exceedance occurred in the 1992 meteorological year. This exceedance only occurred one day in three years or less than 0.1 percent of the time. Therefore, CDM is recommending that no further visibility analysis is required. Results are shown in **Table 7-1** for each year of meteorological data.

The results of the sensitive Class II area modeling is presented in **Table 7-2**. The highest change in 24-hour light extinction (75.54 percent) occurred at the Ybor City Museum State Park in Tampa in 1990. This state park is located approximately 22 km from The Facility.

Table 7-1
Class I Visibility Modeling Results

Class I - Chassahowitzka Wildlife Refuge, 24-hr Average

	1990	1992	1996	Threshold
Largest Change in Extinction, Db_{ext}	2.55%	5.43%	0.00%	5%
Largest Delta-Deciview, DDV	0.252	0.529	0.000	
Maximum Extinction, (Mm^{-1})	25.373	25.329	27.196	

CALPOST was used to calculate visibility parameters using S and N concentrations calculated using the CALPUFF dispersion model.

Table 7-2
Class II Visibility Modeling Results

Class II - Scenic Areas, 24-hr Average

	1990	1992	1996
Largest Change in Extinction, Db_{ext}	75.54%	39.97%	48.90%
Largest Delta-Deciview, DDV	5.627	3.363	3.981
Maximum Extinction, (Mm^{-1})	21.922	22.445	22.465

CALPOST was used to calculate visibility parameters using S and N concentrations calculated using the CALPUFF dispersion model.

7.2 Minor Source Growth

Minor source growth impacts from the project are required under 40 CFR 51.166(o) and Rule 62-212.400(5). They require an analysis of population growth and other factors to qualitatively assess the amount of PSD consumption by minor sources since August 7, 1977, as defined in 40 CFR 51.166(n)(3)(ii).

Section 6, Tables 6-10 and 6-11 show that the proposed Unit 4 modeled air quality impacts would be well below PSD Class II Area and Class I Area Significant Impact Levels. Therefore, there would be no Significant Impact Area. In other words, there would be no "area the facility or modification would affect." Nonetheless, an evaluation of additional impacts from the proposed Unit 4 is presented below.

Hillsborough County has experienced substantial growth since 1980. **Table 7-3** shows that the population of Hillsborough County has grown by 42 percent since 1980. However, in spite of this population growth, air pollutant concentrations have not generally increased over the same period, as shown in **Figure 7-1**. This figure shows historical air pollutant concentrations taken at the monitoring stations nearest to the Facility, as listed in Section 5, Table 5-4. Air quality in Hillsborough County has remained good in this 20-year period. As shown in Section 5, Table 5-5, the County is in attainment of all of the National and Florida Ambient Air Quality Standards, and air pollutant concentrations are all well below the standards. Therefore, the population growth has not had a detrimental effect on air quality in Hillsborough County.

Table 7-3
Population Change for Hillsborough County, 1980 to 2004 [1]

	Population				Percent Change		
County	**2004**	**2000**	**1990**	**1980**	**2000-2004**	**1990-2000**	**1980-1990**
Hillsborough	1,108,435	998,948	834,054	646,939	9.9%	16.5%	22.4%

Source: [1] Bureau of Business and Economic Research, Florida Estimates of Population, April 2004.

Unit 4 air pollutant emissions rates are summarized in **Table 7-4**. As shown in this table, these annual emissions rates would represent less than 0.25 percent of the Hillsborough County totals for 1999 (the most recent year available from the U.S. EPA's AirData website). These emissions comparison and detailed dispersion modeling analyses presented in Section 6 and 7 show that Unit 4 would have an insignificant effect on Hillsborough County air quality.

Table 7-4
Comparison of Unit 4 and Hillsborough County Air Pollutant Emission Rates

	CO (tons/yr)	NO_x (tons/yr)	PM_{10} (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)
Unit 4	113.4	256.1	25.5	66.1	12.0
Hillsborough County	313,918	111,237	34,817	166,516	52,205
Unit 4 Percent of Total	0.04%	0.23%	0.07%	0.04%	0.02%

Source: U.S. EPA AirData, http://www.epa.gov/air/data/reports.html.

7.2.1 Employment

Employment figures for Hillsborough County, according to the Florida Labor Market Statistics published in 2004 (http://www.labormarketinfo.com), show 740,336 persons employed. This number is anticipated to grow at a rate of approximately 2.51 percent a year through 2012, bringing the total number of employed people to 888,914 in 2012. Once Unit 4 is operational, it will employ approximately eight additional people, for a total of 50 employees. The proposed Unit 4 will be managed by Covanta's current staff. It is anticipated that the majority of these personnel requirements will be filled from within the local labor force. Significant in-migration to the area is therefore not anticipated. As a result, no increase in population in the area attributable to the addition of Unit 4 is expected to occur.

The project does not require the destruction, relocation or alteration of any residential property in the area. In addition, since no net migration to the area is anticipated, there will be no change in demand for housing units in the area.

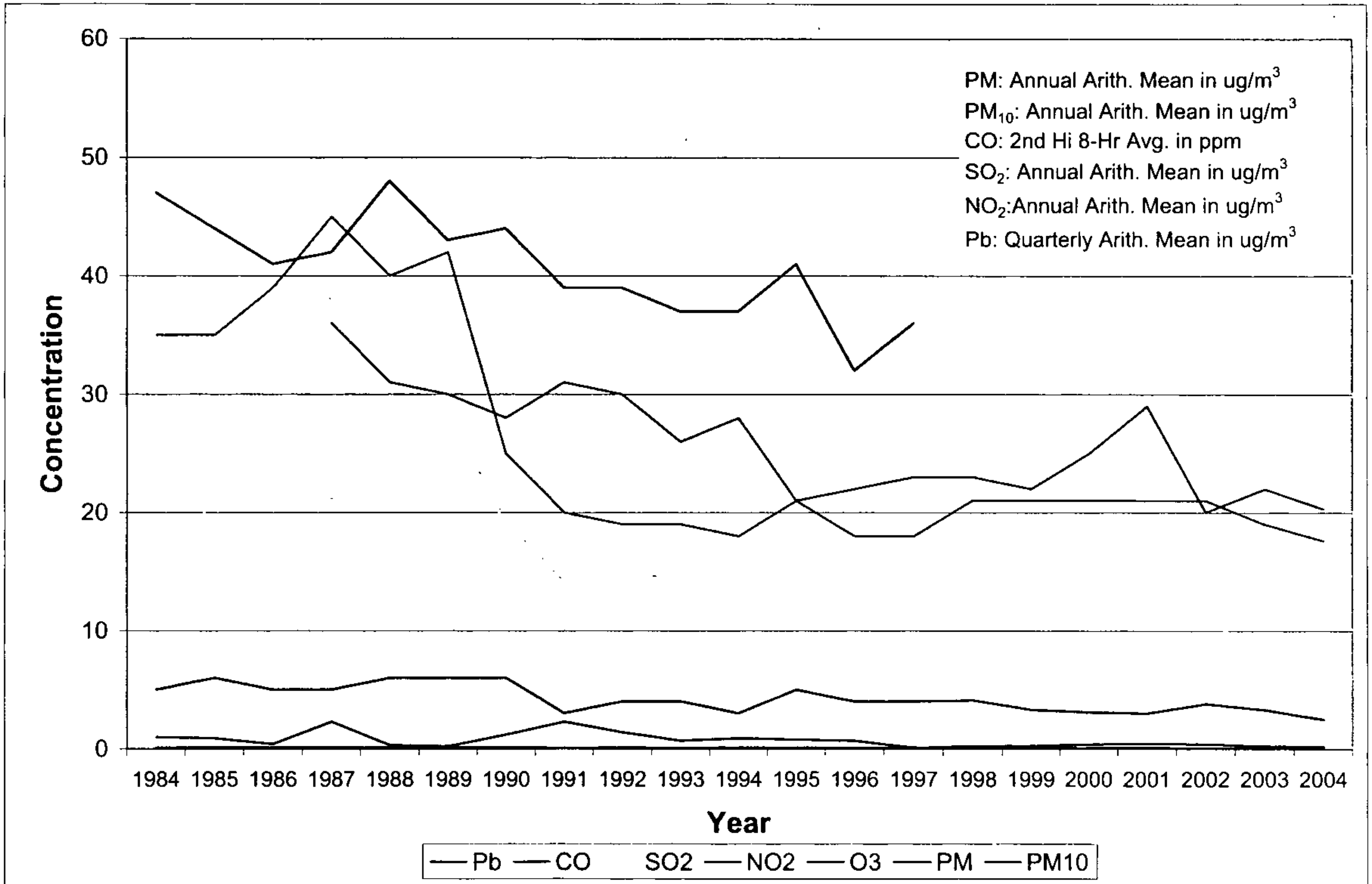
The construction and operation of the Unit 4 will have a minor positive net effect on industrial and commercial development. It is not anticipated that this effect will be significant when considered on a regional basis.

The growth analysis indicates that no net significant change in employment, populations, housing, or commercial/industrial development will be associated with the project. As a result, there will not be any significant increases in pollutant emissions indirectly associated with Unit 4.

7.3 Vegetation and Soils

Federal and Florida regulations require that an assessment be undertaken of the potential impacts of emissions from a proposed facility on soils and vegetation of commercial or recreational value (40 CFR 51.166(o)(1) and 62-212.400(5)(e)1.a Florida Administrative Code [FAC]). Pollutant emissions from Unit 4 were used to compute potential impacts on soils and vegetation. Vegetative impacts from airborne pollutants may result from deposition on leaf surfaces as particulate matter (dry deposition), from solutions in rainfall (wet deposition), or by gaseous exchange. Airborne components may also enter vegetation through roots following deposition to soils. Accumulation of airborne pollutants in soil can also lead to changes in soil characteristics.

Total nitrogen and total sulfur deposition modeling was conducted using the CALPUFF model, to assess any potential impacts at the Chassahowitzka Wildlife Refuge. Deposition estimates, in units of $g/(m^2 \cdot s)$, needed to be adjusted to compare modeling results with the limit of 0.1 $kg/(ha \cdot yr)$ of elemental sulfur (S) and nitrogen (N), as required by NPS. The CALPUFF results for each pollutant were individually converted to kg/ha using the CALPOST post-processor. Molecular weight differences between S or N and a specific pollutant were corrected using the multipliers presented in **Tables 7-5** and **7-6**.



Source: FDEP Quick Look Reports, 1984-2004, http://www.dep.state.fl.us/Air/publications/techrpt/quicklook.htm.

CDM

Figure 7-1
Hillsborough County Air Pollution Trends

7.3.1 Total Sulfur Deposition

Sulfuric acid (H_2SO_4) is formed when gaseous SO_3 produced by a source reacts with water droplets. The acidified water vapor can result in acidic precipitation (acid rain). Plant sensitivity to sulfur dioxide (SO_2) appears to vary not only with the climate of an area, but also with the duration of exposure.

Wet and dry deposition fluxes of SO_2 and $SO_4^=$ were calculated for Unit 4. Deposition results were converted to kg/(ha·yr) and normalized for S deposition using the multipliers listed in **Table 7-5**. The maximum annual average from all receptors modeled was used for the comparison. As Table 7-4 shows, total S deposition resulting from Unit 4 does not exceed NPS's 0.1 kg/(ha·yr) threshold.

7.3.2 Total Nitrogen Deposition

Nitrogen dioxide (NO_2) can be beneficial to vegetation in small amounts. Uptake of NO_2 varies with a number of factors such as nutrient supply in the soil, fertilization, and rainfall. NO_2 can also be converted to nitric acid (HNO_3) and contribute to acid precipitation.

The dry deposition fluxes of nitrogen oxides (NO_X), HNO_3, and NO_3^-, as well as the wet deposition flux of HNO_3 were calculated for the Unit 4. Deposition results were converted to kg/(ha·yr) and normalized for N deposition using the multipliers listed in **Table 7-6**. The maximum annual average from all receptors modeled was used for the comparison. As Table 7-5 shows, total N deposition resulting from Unit 4 does not exceed NPS's 0.1 kg/(ha·yr) threshold.

Table 7-5
Total Sulfur Deposition Results

Class 1 – Chassahowitzka Wildlife Refuge, Annual Average S Deposition (kg/ha*yr)

	1990, 1996 Multiplier*	1992 Multiplier*	1990	1992	1996	
SO_2, Dry Deposition	157680000	155088000	4.12E-04	5.59E-04	3.29E-04	
SO_2, Wet Deposition	157680000	155088000	4.54E-04	4.47E-04	4.55E-04	
SO_4^{2-}, Dry Deposition	105118949	103390966	1.12E-05	1.18E-05	1.20E-05	
SO_4^{2-}, Wet Deposition	105118949	103390966	5.87E-04	5.90E-04	6.00E-04	
Total S Deposition:			1.46E-03	1.61E-03	1.40E-03	

* Multiplier is applied using CALPOST to convert from the pollutant specific (ug/m^2*s) values in the wet and dry deposition CALPUFF output files, to sulfur deposition values (in kg/ha*yr) for comparison with the NPS limit of 0.1 (kg/ha*yr)

Deposition of	Year	Ratio of MW of Pollutant to S	g to kg	m2 to ha	sec to hr	hr to year	Multiplier
S from SO2	1990, 1996	0.5	0.001	10000	3600	8760	157680000
S from SO4	1990, 1996	0.33333	0.001	10000	3600	8760	105118949
S from SO2	1992	0.5	0.001	10000	3600	8616	155088000
S from SO4	1992	0.33333	0.001	10000	3600	8616	103390966

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Table 7-6
Total Nitrogen Deposition Results

Class 1 - Chassahowitzka Wildlife Refuge, Annual Average N Deposition (kg/ha*yr)

	1990, 1996	**1992**				
	Multiplier*	**Multiplier***	**1990**	**1992**	**1996**	
NO_X, Dry Deposition	95979816	94402066	1.40E-04	2.71E-04	1.80E-04	
HNO_3, Dry Deposition	70079299	68927311	1.74E-04	1.87E-04	7.18E-05	
HNO_3, Wet Deposition	70079299	68927311	2.23E-04	2.43E-04	1.40E-04	
NO_3^{1-}, Dry Deposition	71211442	70040843	2.14E-06	3.60E-06	3.21E-06	
NO_3^{1-}, Wet Deposition	71211442	70040843	1.02E-04	2.83E-04	1.90E-04	
Total N Deposition:			6.41E-04	9.88E-04	5.86E-04	

* Multiplier is applied using CALPOST to convert from the pollutant specific (ug/m^2*s) values in the wet and dry deposition CALPUFF output files, to sulfur deposition values (in kg/ha*yr) for comparison with the NPS limit of 0.1 (kg/ha*yr)

Deposition of	**Year**	**Ratio of MW of Pollutant to N**	**g to kg**	**m2 to ha**	**sec to hr**	**hr to year**	**Multiplier**
N from NO_X	1990, 1996	0.30435	1.00E-03	10000	3600	8760	95979816
N from HNO_3	1990, 1996	0.22222	1.00E-03	10000	3600	8760	70079299
N from NO_3^-	1990, 1996	0.22581	1.00E-03	10000	3600	8760	71211442
N from NO_X	1992	0.30435	1.00E-03	10000	3600	8616	94402066
N from HNO_3	1992	0.22222	1.00E-03	10000	3600	8616	68927311
N from NO_3^-	1992	0.22581	1.00E-03	10000	3600	8616	70040843

Pg. 40 of IWAQM Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December, 1998.

Section 8
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Appendix A
Hillsborough County Resource Recovery Facility
Emissions Calculations Tables

The tables in this Appendix include the emission calculations for the Hillsborough County Resource Recovery Facility PSD permit modification, along with the existing facility MWC units permit emissions limits.

Table Number	Table Name	Description
A-1	Estimated Maximum Potential Emission Rates	Summary of emission factors and emission rates for PSD pollutants emitted from the new MWC unit, lime and carbon silos, cooling tower.
A-2	Estimated Emission Rates for the New MWC Unit	Calculation of the new MWC unit emissions based Best Available Control Technology (BACT) emissions limits.
A-3	Estimated PM Emission Rates for New Lime and Carbon Silos	Calculation of PM/PM_{10} emissions from the proposed lime and carbon silos, based on silo design information and baghouse PM emission limits.
A-4	Estimated PM Emission Rates for New Cooling Tower Cell	Calculation of PM emissions from the cooling tower based on known design parameters and AP-42 estimates.
A-5	Existing Facility Emissions Limits	Summary of permitted emission rates for PSD pollutants emitted from the existing MWC units, lime and carbon silos.

Table A-1
Hillsborough County Resource Recovery Facility New MWC
Estimated Maximum Potential Emission Rates

Source	Emissions, by Air Pollutant																			
	Particulate Matter				Nitrogen Oxides				Carbon Monoxide				Sulfur Dioxide				Hydrogen Chloride			
	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year
600 tpd MWC unit)[1]	0.009	gr/dscf @ 7% O_2	5.72	25.1	110 0	ppmv @ 7% O_2	58.47	256.1	60.0	ppmv @ 7% O_2	25.89	113.4	26.0	ppmv @ 7% O_2	19.25	84.3	60.2	ppmv @ 7% O_2	25 36	111.1
Cooling Tower	0 005	gr/dscf @ 7% O_2	9.62E-02	0 42	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Lime Silos (2 silos)[2]	0.015	gr/dscf actual	1.38E-04	6.05E-04																
Carbon Silo[2]	0 015	gr/dscf actual	3.70E-05	1.6E-04	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Facility	—	—	—	**25.5**	—	—	—	**256.1**	—	—	—	**113.4**	—	—	—	**84.3**	—	—	—	**111.1**
Emission Thresholds																				
PSD Significant Increase (Major Modification)				25 (15 PM_{10})				40				100				40				40

Source	Emissions, by Air Pollutant																			
	Hydrogen Fluoride				Sulfuric Acid Mist				Dioxins and Furans				Mercury				Cadmium			
	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year
600 tpd MWC unit)[1]	3.5	ppmv @ 7% O_2	0.81	3.5	15.0	ppmv @ 7% O_2	17 00	74 4	13.0	ng/dscm @ 7% O_2	3.61E-06	1.58E-05	0.134	mg/dscm @ 7% O_2	3.71E-02	1.63E-01	0.020	mg/dscm @ 7% O_2	5.56E-03	2 43E-02
Cooling Tower	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Lime Silos (2 silos)[2]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Carbon Silo[2]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Facility	—	—	—	**3.5**	—	—	—	**74.4**	—	—	—	**1.6E-05**	—	—	—	**1.6E-01**	—	—	—	2.4E-02
Emission Thresholds																				
PSD Significant Increase (Major Modification)				3				7				3.50E-06				0.1				15

Source	Emissions, by Air Pollutant															
	Lead				Metals				Ammonia				Volatile Organic Compounds			
	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year	Emission Factor	Units	lb/hr	ton/year
600 tpd MWC unit)[1]	0 20	mg/dscm @ 7% O_2	5.56E-02	0.24	0.009	gr/dscf @ 7% O_2	5 72	25.1	50.00	ppmv @ 7% O_2	9.82	43 0	0.10	lbs/ton	2.75	12.0
Cooling Tower	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Lime Silos (2 silos)[2]																
Carbon Silo[2]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Facility	—	—	—	0.24	—	—	—	**25.1**	—	—	—	43.0	—	—	—	12 0
Emission Thresholds																
PSD Significant Increase (Major Modification)				0.6				15				—				40

Bold Text denotes an excedence of the PSD threshold

Notes:

[1] Emissions based on vendor information, dated _____, 2004, attached. BACT emission rate for NO_x based on selective non-catalytic reduction and flue gas recirculation (SNCR & FGR).

[2] Emissions factors calculated based on estimated baghouse emission rate of 0 015 gr/dscf.

Table A-2
Hillsborough County Resource Recovery Facility
Estimated Emission Rates for the New MWC Unit

Flue gas flow at stack exit	74,188 dscfm, with	7% O_2 conc.	
PM Concentration[1]	0.009 gr/dscf of PM	7% O_2 conc.	
NO_X Concentration[2]	110 ppmv, corrected to	7% O_2 conc.	
CO Concentration[1]	80 ppmv, corrected to	7% O_2 conc.	
SO_2 Concentration[1]	26 ppmv, corrected to	7% O_2 conc.	
HCl Concentration[1,3]	1204 ppmv, corrected to	7% O_2 conc.	(uncontrolled)
HF Concentration[1]	3.5 ppmv, corrected to	7% O_2 conc.	
SAM Concentration[1]	15 ppmv, corrected to	7% O_2 conc.	
PCDD/PCDF Concentration[1,4]	13 ng/dscm, corrrected to	7% O_2 conc.	
Hg Concentration[1,3]	0.89 mg/dscm, corrrected to	7% O_2 conc.	(uncontrolled)
Cd Concentration[1,4]	0.02 mg/dscm, corrrected to	7% O_2 conc.	
Pb Concentration[1,4]	0.2 mg/dscm, corrrected to	7% O_2 conc.	
Metals Concentration[1]	0.009 gr/dscf of PM	7% O_2 conc.	
NH_3 Concentration[1]	50 ppmv, corrected to	7% O_2 conc.	
VOC Concentration[5]	0.1 lb/ton		

PM Emissions

Calculate PM emission rate:

$$\frac{0.009 \text{ grains}}{1 \text{ dscf}} \cdot \frac{74{,}188 \text{ dscf}}{1 \text{ min}} \cdot \frac{1 \text{ g}}{15.43 \text{ grain}} \cdot \frac{1 \text{ min}}{60 \text{ sec}} = \boxed{0.72 \ \frac{\text{g}}{\text{sec}}}$$

Calculated PM annual emission rate:

$$\frac{0.72 \text{ g}}{\text{sec}} \cdot \frac{1 \text{ ton}}{907200 \text{ g}} \cdot \frac{60 \text{ sec}}{1 \text{ min}} \cdot \frac{60 \text{ min}}{1 \text{ hour}} \cdot \frac{24 \text{ hour}}{1 \text{ day}} \cdot \frac{365 \text{ days}}{1 \text{ year}} = \boxed{25.07 \ \frac{\text{ton}}{\text{year}}}$$

Nitrogen Oxide Emissions

Dry volumetric flow rate:

$$\begin{array}{c}74{,}188 \text{ dscfm}\\ @\ 7\%\ O_2\end{array} \cdot \frac{1 \text{ dscm}}{35.31 \text{ dscf}} \cdot \frac{1 \text{ min}}{60 \text{ sec}} = \frac{35.02 \text{ dscm}}{1 \text{ sec}}$$

Calculated NO_x emission rate:

$$\frac{110.00 \text{ mol } NO_2}{1.E{+}06 \text{ moles}} \cdot \frac{41.57 \text{ moles}}{1 \text{ dscm}} \cdot \frac{46.01 \text{ g}}{1 \text{ mole}} = \frac{0.210 \text{ g}}{\text{dscm}}$$

$$\frac{0.210 \text{ g}}{\text{dscm}} \cdot \frac{35.02 \text{ dscm}}{1 \text{ sec}} = \boxed{7.37 \ \frac{\text{g}}{\text{sec}}}$$

Calculated NO_x annual emission rate:

$$\frac{7.37 \text{ g}}{\text{sec}} \cdot \frac{1 \text{ ton}}{907200 \text{ g}} \cdot \frac{60 \text{ sec}}{1 \text{ min}} \cdot \frac{60 \text{ min}}{1 \text{ hour}} \cdot \frac{24 \text{ hour}}{1 \text{ day}} \cdot \frac{365 \text{ days}}{1 \text{ year}} = \boxed{256.10 \ \frac{\text{ton}}{\text{year}}}$$

Carbon Monoxide Emissions

Dry volumetric flow rate:

$$\begin{array}{c}74{,}188 \text{ dscfm}\\ @\ 7\%\ O_2\end{array} \cdot \frac{1 \text{ dscm}}{35.31 \text{ dscf}} \cdot \frac{1 \text{ min}}{60 \text{ sec}} = \frac{35.02 \text{ dscm}}{1 \text{ sec}}$$

Calculated CO emission rate:

$$\frac{80.00 \text{ mol CO}}{1.E{+}06 \text{ moles}} \cdot \frac{41.57 \text{ moles}}{1 \text{ dscm}} \cdot \frac{28.01 \text{ g}}{1 \text{ mole}} = \frac{0.093 \text{ g}}{\text{dscm}}$$

$$\frac{0.093 \text{ g}}{\text{dscm}} \cdot \frac{35.02 \text{ dscm}}{1 \text{ sec}} = \boxed{3.26 \ \frac{\text{g}}{\text{sec}}}$$

Calculated CO annual emission rate:

$$\frac{3.26 \text{ g}}{\text{sec}} \cdot \frac{1 \text{ ton}}{907200 \text{ g}} \cdot \frac{60 \text{ sec}}{1 \text{ min}} \cdot \frac{60 \text{ min}}{1 \text{ hour}} \cdot \frac{24 \text{ hour}}{1 \text{ day}} \cdot \frac{365 \text{ days}}{1 \text{ year}} = \boxed{113.39 \ \frac{\text{ton}}{\text{year}}}$$

Table A-2
Hillsborough County Resource Recovery Facility
Estimated Emission Rates for the New MWC Unit

Sulfur Dioxide Emissions

[illegible]y volumetric flow rate:

$$\genfrac{}{}{0pt}{}{74{,}188\ \text{dscfm}}{@\ 7\%\ O_2} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} = \frac{35.02\ \text{dscm}}{1\ \text{sec}}$$

Calculated SO_2 emission rate:

$$\frac{26.00\ \text{mol}\ SO_2}{1.\text{E}{+}06\ \text{moles}} \cdot \frac{41.57\ \text{moles}}{1\ \text{dscm}} \cdot \frac{64.07\ \text{g}}{1\ \text{mole}} = \frac{0.069\ \text{g}}{\text{dscm}}$$

$$\frac{0.069\ \text{g}}{\text{dscm}} \cdot \frac{35.02\ \text{dscm}}{1\ \text{sec}} = \boxed{\frac{2.42\ \text{g}}{\text{sec}}}$$

Calculated SO_2 annual emission rate:

$$\frac{2.42\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{84.29\ \text{ton}}{\text{year}}}$$

Hydrogen Chloride Emissions

Dry volumetric flow rate:

$$\genfrac{}{}{0pt}{}{74{,}188\ \text{dscfm}}{@\ 7\%\ O_2} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} = \frac{35.02\ \text{dscm}}{1\ \text{sec}}$$

Calculated HCl emission rate:

$$\frac{1204.00\ \text{mol HCl}}{1.\text{E}{+}06\ \text{moles}} \cdot \frac{41.57\ \text{moles}}{1\ \text{dscm}} \cdot \frac{36.46\ \text{g}}{1\ \text{mole}} = \frac{1.825\ \text{g}}{\text{dscm}}$$

$$\frac{1.825\ \text{g}}{\text{dscm}} \cdot \frac{35.02\ \text{dscm}}{1\ \text{sec}} \cdot (100\%{-}95\%) = \boxed{\frac{3.20\ \text{g}}{\text{sec}}}$$

Calculated HCl annual emission rate:

$$\frac{3.20\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{111.07\ \text{ton}}{\text{year}}}$$

Hydrogen Flouride Emissions

Dry volumetric flow rate:

$$\genfrac{}{}{0pt}{}{74{,}188\ \text{dscfm}}{@\ 7\%\ O_2} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} = \frac{35.02\ \text{dscm}}{1\ \text{sec}}$$

Calculated HF emission rate:

$$\frac{3.50\ \text{mol HF}}{1.\text{E}{+}06\ \text{moles}} \cdot \frac{41.57\ \text{moles}}{1\ \text{dscm}} \cdot \frac{20.01\ \text{g}}{1\ \text{mole}} = \frac{0.003\ \text{g}}{\text{dscm}}$$

$$\frac{0.003\ \text{g}}{\text{dscm}} \cdot \frac{35.02\ \text{dscm}}{1\ \text{sec}} = \boxed{\frac{0.102\ \text{g}}{\text{sec}}}$$

Calculated HF annual emission rate:

$$\frac{0.102\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{3.54\ \text{ton}}{\text{year}}}$$

Sulfuric Acid Mist (SAM) Emissions

Dry volumetric flow rate:

$$\genfrac{}{}{0pt}{}{74{,}188\ \text{dscfm}}{@\ 7\%\ O_2} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} = \frac{35.02\ \text{dscm}}{1\ \text{sec}}$$

Calculated SAM emission rate:

$$\frac{15.00\ \text{mol SAM}}{1.\text{E}{+}06\ \text{moles}} \cdot \frac{41.57\ \text{moles}}{1\ \text{dscm}} \cdot \frac{98.08\ \text{g}}{1\ \text{mole}} = \frac{0.061\ \text{g}}{\text{dscm}}$$

$$\frac{0.061\ \text{g}}{\text{dscm}} \cdot \frac{35.02\ \text{dscm}}{1\ \text{sec}} = \boxed{\frac{2.14\ \text{g}}{\text{sec}}}$$

Calculated SAM annual emission rate:

$$\frac{2.142\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{74.45\ \text{ton}}{\text{year}}}$$

Table A-2
Hillsborough County Resource Recovery Facility
Estimated Emission Rates for the New MWC Unit

Dioxins/Furans (PCDD/PCDF) Emissions

lculated PCDD/PCDF emission rate:

$$\frac{13\ \text{ng}}{1\ \text{dscm}} \cdot \frac{74{,}188\ \text{dscf}}{1\ \text{min}} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} \cdot \frac{1\ \text{g}}{1.\text{E+}09\ \text{ng}} = \boxed{4.55\text{E-}07\ \frac{\text{g}}{\text{sec}}}$$

Calculated PCDD/PCDF annual emission rate:

$$\frac{4.6\text{E-}07\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{1.58\text{E-}05\ \frac{\text{ton}}{\text{year}}}$$

Mercury Emissions

Calculated Hg emission rate:

$$\frac{0.89\ \text{mg}}{1\ \text{dscm}} \cdot \frac{74{,}188\ \text{dscf}}{1\ \text{min}} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} \cdot \frac{1\ \text{g}}{1.\text{E+}03\ \text{mg}} \cdot (100\%\text{-}85\%) = \boxed{4.67\text{E-}03\ \frac{\text{g}}{\text{sec}}}$$

Calculated Hg annual emission rate:

$$\frac{4.7\text{E-}03\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{1.63\text{E-}01\ \frac{\text{ton}}{\text{year}}}$$

Cadmium Emissions

Calculated Cd emission rate:

$$\frac{0.02\ \text{mg}}{1\ \text{dscm}} \cdot \frac{74{,}188\ \text{dscf}}{1\ \text{min}} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} \cdot \frac{1\ \text{g}}{1.\text{E+}03\ \text{mg}} = \boxed{7.0\text{E-}04\ \frac{\text{g}}{\text{sec}}}$$

Calculated Cd annual emission rate:

$$\frac{7.0\text{E-}04\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{2.43\text{E-}02\ \frac{\text{ton}}{\text{year}}}$$

Lead Emissions

Calculated Pb emission rate:

$$\frac{0.2\ \text{mg}}{1\ \text{dscm}} \cdot \frac{74{,}188\ \text{dscf}}{1\ \text{min}} \cdot \frac{1\ \text{dscm}}{35.31\ \text{dscf}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} \cdot \frac{1\ \text{g}}{1.\text{E+}03\ \text{mg}} = \boxed{7.00\text{E-}03\ \frac{\text{g}}{\text{sec}}}$$

Calculated Pb annual emission rate:

$$\frac{7.0\text{E-}03\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{2.43\text{E-}01\ \frac{\text{ton}}{\text{year}}}$$

Metals Emissions

Calculated Metals emission rate:

$$\frac{0.009\ \text{grains}}{1\ \text{dscf}} \cdot \frac{74{,}188\ \text{dscf}}{1\ \text{min}} \cdot \frac{1\ \text{g}}{15.43\ \text{grain}} \cdot \frac{1\ \text{min}}{60\ \text{sec}} = \boxed{0.72\ \frac{\text{g}}{\text{sec}}}$$

Calculated Metals annual emission rate:

$$\frac{0.72\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{25.07\ \frac{\text{ton}}{\text{year}}}$$

Table A-2
Hillsborough County Resource Recovery Facility
Estimated Emission Rates for the New MWC Unit

Ammonia Emissions

[illegible]ry volumetric flow rate:

$$\frac{74{,}188 \text{ dscfm}}{@\ 7\%\ O_2} \cdot \frac{1 \text{ dscm}}{35.31 \text{ dscf}} \cdot \frac{1 \text{ min}}{60 \text{ sec}} = \frac{35.02 \text{ dscm}}{1 \text{ sec}}$$

Calculated NH_3 emission rate:

$$\frac{50.00 \text{ mol } NH_3}{1.E{+}06 \text{ moles}} \cdot \frac{41.57 \text{ moles}}{1 \text{ dscm}} \cdot \frac{17 \text{ g}}{1 \text{ mole}} = \frac{0.035 \text{ g}}{\text{dscm}}$$

$$\frac{0.035 \text{ g}}{\text{dscm}} \cdot \frac{35.02 \text{ dscm}}{1 \text{ sec}} = \boxed{\mathbf{1.24} \ \frac{\mathbf{g}}{\mathbf{sec}}}$$

Calculated NH_3 annual emission rate:

$$\frac{1.24 \text{ g}}{\text{sec}} \cdot \frac{1 \text{ ton}}{907200 \text{ g}} \cdot \frac{60 \text{ sec}}{1 \text{ min}} \cdot \frac{60 \text{ min}}{1 \text{ hour}} \cdot \frac{24 \text{ hour}}{1 \text{ day}} \cdot \frac{365 \text{ days}}{1 \text{ year}} = \boxed{\mathbf{43.01} \ \frac{\mathbf{ton}}{\mathbf{year}}}$$

VOC Emissions

Calculated VOC emission rate:

$$\frac{0.10 \text{ lbs}}{\text{ton}} \cdot \frac{660 \text{ tons}}{1 \text{ day}} \cdot \frac{1 \text{ day}}{24 \text{ hrs}} \cdot \frac{1 \text{ hr}}{3600 \text{ sec}} \cdot \frac{453.59 \text{ g}}{1 \text{ lbs}} = \boxed{\mathbf{0.35} \ \frac{\mathbf{g}}{\mathbf{sec}}}$$

Calculated VOC annual emission rate:

$$\frac{0.35 \text{ g}}{\text{sec}} \cdot \frac{1 \text{ ton}}{907200 \text{ g}} \cdot \frac{60 \text{ sec}}{1 \text{ min}} \cdot \frac{60 \text{ min}}{1 \text{ hour}} \cdot \frac{24 \text{ hour}}{1 \text{ day}} \cdot \frac{365 \text{ days}}{1 \text{ year}} = \boxed{\mathbf{12.04} \ \frac{\mathbf{ton}}{\mathbf{year}}}$$

Sources:

[1] Lee County Energy Recovery Facility Prevention of Significant Deterioration Air Permit Application, February 2003 and Lee County Resource Recovery Facility Air Construction Permit 0710119-002-AC, PSD-FL-151C, October 13, 2003.

[2] Upperbound NO_x concentration limit of 110 ppmv @ 7% O_2 for the selective non-catalytic reduction (SNCR) with flue gas circulation system.

[3] Uncontrolled concentration is based on 95% confidence interval of 2000-2002 stack test results for the existing Hillsborough County RRF MWC Units 1-3 multiplied by a factor of 1.5 (660 tpd/440 tpd) to account for increase capacity of the proposed Unit 4.

[4] 40 CFR 60, Subpart Eb New Source Performance Standards for New Municipal Waste Combustors.

[5] Based on Harrisonburg, VA Resource Recovery Facility VOC emission limit of 0.1 lb/ton.

Table A-3
Hillsborough County Resource Recovery Facility
Estimated PM Emission Rates for New Lime and Carbon Silos

Pebble Lime Storage Silo

PM Concentration	0.015 gr/dscf of PM
Volume of each Silo	2900 dscf
Airflow Throughput Rate	2900 dscf/2 days (based on silo refill every 2 days)
Amount of air displaced	1450 dscf/day

Calculated PM emission rate:

$$\frac{0.015\ \text{grains}}{1\ \text{dscf}} \cdot \frac{1450.0\ \text{dscf}}{1\ \text{day}} \cdot \frac{1\ \text{g}}{15.43\ \text{grain}} \cdot \frac{1\ \text{day}}{24\ \text{hour}} \cdot \frac{1\ \text{hour}}{60\ \text{min}} \cdot \frac{1\ \text{min}}{60\ \text{second}} = \boxed{\frac{1.6\text{E-}05\ \text{g}}{\text{sec}}}$$

Calculated PM annual emission rate:

$$\frac{1.63\text{E-}05\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{5.67\text{E-}04\ \text{ton}}{\text{year}}}$$

Dolomitic Lime Storage Silo

PM Concentration	0.015 gr/dscf of PM
Volume of each Silo	2900 dscf
Airflow Throughput Rate	2900 dscf/30 days (based on silo refill once per month)
Amount of air displaced	96.67 dscf/day

Calculated PM emission rate:

$$\frac{0.015\ \text{grains}}{1\ \text{dscf}} \cdot \frac{96.7\ \text{dscf}}{1\ \text{day}} \cdot \frac{1\ \text{g}}{15.43\ \text{grain}} \cdot \frac{1\ \text{day}}{24\ \text{hour}} \cdot \frac{1\ \text{hour}}{60\ \text{min}} \cdot \frac{1\ \text{min}}{60\ \text{second}} = \boxed{\frac{1.1\text{E-}06\ \text{g}}{\text{sec}}}$$

Calculated PM annual emission rate:

$$\frac{1.09\text{E-}06\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{3.78\text{E-}05\ \text{ton}}{\text{year}}}$$

Carbon Storage Silos

PM Concentration	0.015 gr/dscf of PM
Volume of each Silo	2900 dscf
Airflow Throughput Rate	2900 dscf/7 days (based on silo refill once per week)
Amount of air displaced	414.3 dscf/day

Calculated PM emission rate:

$$\frac{0.015\ \text{grains}}{1\ \text{dscf}} \cdot \frac{414.3\ \text{dscf}}{1\ \text{day}} \cdot \frac{1\ \text{g}}{15.43\ \text{grain}} \cdot \frac{1\ \text{day}}{24\ \text{hour}} \cdot \frac{1\ \text{hour}}{60\ \text{min}} \cdot \frac{1\ \text{min}}{60\ \text{second}} = \boxed{\frac{4.7\text{E-}06\ \text{g}}{\text{sec}}}$$

Calculated PM annual emission rate:

$$\frac{4.66\text{E-}06\ \text{g}}{\text{sec}} \cdot \frac{1\ \text{ton}}{907200\ \text{g}} \cdot \frac{60\ \text{sec}}{1\ \text{min}} \cdot \frac{60\ \text{min}}{1\ \text{hour}} \cdot \frac{24\ \text{hour}}{1\ \text{day}} \cdot \frac{365\ \text{days}}{1\ \text{year}} = \boxed{\frac{1.62\text{E-}04\ \text{ton}}{\text{year}}}$$

Table A-4
Hillsborough County Resource Recovery Facility
Estimated PM Emission Rates for New Cooling Tower Cell

A. Flow Rate Across Cooling Tower Cell	11000	gal/min
B. Total Dissolved Solids[1]	3,500	ppm
C. Drift as a Percentage of Recirculating Rate	0.001%	Vendor information
D. Density of Water	8.330	lb/gal
E. Percentage of Drift PM that Evaporates to PM_{10}[2]	50%	
F. Total PM_{10} Emissions within Drift ($A*B*C/10^6*D*60$)	9.62E-02	lbs/hour
G. Hours of Operations	8760	hours/year
H. Annual PM_{10} Emissions for tower (E*F/2000)	**4.21E-01**	**tons/yr**
I. Modeling Emission Rate (g/s)	**1.21E-02**	**g/s**

Sources:

[1] ChemTreat, Inc. Cooling Water Conductivity and Total Dissolved Solids (TDS) of Hillsborough County Resource Recovery Facility Cooling Tower, 5/12/05.

[2] J. Reisman and G. Frisbie, Calculating Realistic PM10 Emissions from Cooling Towers, Presented at Air & Waste Management Association Annual Conference.

Table A-5
Hillsborough County Resource Recovery Facility
Existing Facility Emission Limits

	Existing Facility Emissions Permit Limits per MWC Unit			
Pollutant	***Flue Gas Concentration Limit @ 7% O_2***	***Hourly Emission Limit (lb/hr)***	***Annual Emission Limit (tons/year)***	***Air Modeling Emission Rate (g/s)***
Sulfur Dioxide (SO_2)	29 ppmdv 75% reduction[3]	32.86	143.9	4.14
Nitrogen Oxides (NO_x)	205 ppmdv	58.63	256.0	7.39
Carbon Monoxide (CO)	100 ppmdv	17.4	76.26	2.19
Particulate Matter (PM)[1]	27 mg/dscm	4.1	17.96	0.52
Dioxin[2]	30 ng/dscm	4.50E-06	1.96E-05	5.67E-07
Mercury (Hg)	0.07 mg/dscm[4] or 85% reduction[3]	0.02	0.087	2.52E-03
Cadmium (Cd)	0.04 mg/dscm	6.00E-03	0.026	7.56E-04
Lead (Pb)	0.44 mg/dscm	0.065	0.288	8.19E-03
Hydrogen Chloride (HCl)	29 ppmdv 95% reduction[3]	17	74.43	2.14
Hydrogen Fluoride (HF)	6.74 mg/dscm	1.0	4.43	0.13
Volatile Organic Compounds (VOCs)	0.01 gr/dscf[5] 0.2 lb/ton[6]	--[7]	--[7]	--
Sulfuric Acid Mist (SAM)	0.072 gr/dscf[9]	--[7]	--[7]	--

Notes:

[1] For purposes of analysis, PM10 is equivalent to PM.

[2] Total tetra through octa PCDD and PCDF.

[3] Whichever is less stringent.

[4] The Florida Mercury Rule concentration standard of 0.070 mg/dscm @7% O_2 is more stringent than Subpart Eb concentration standard of 0.080 mg/dscm @7% O_2. However the removal requirement of 80% is less stringent than the 85% removal required in Subpart Eb; therefore, a mix of both regulations would apply (i.e., 0.070 mg/dscm @7% O_2, or 85% removal, whichever is less stringent).

[5] Corrected at 12% CO_2.

[6] Whichever is more restrictive.

[7] To be demonstrated during initial compliance test only.

	Existing Facility - Supporting Equipment Particulate Matter Emissions Limits			
Source	***Flue Gas Concentration Limit***	***Hourly Emission Limit (lb/hr)***	***Annual Emission Limit (tons/year)***	***Air Modeling Emission Rate (g/s)***
Ash Building and Handling System[1]	-- 5% opacity	1.63	7.1	0.89
Lime Silo	0.015 gr/dscf 5% opacity	--	--	--
Dolomitic Lime Silo	-- 20% opacity	6.32	0.39	0.80
Carbon Silo	0.015 gr/dscf 5% opacity	--	--	--

Notes:

[1] No visible emissions in exess of 5% of the observation period.

RILEYPower
A Babcock Power Inc. Company

Dennis M. Malone
Proposal Manager

July 29, 2005

Mr. Frank C. Sapienza
CAMP DRESSER & McKEE INC
50 Hampshire Street
Cambridge, MA 02139
REFERENCE: Request for Selective Catalytic Reduction Information

Dear Mr. Sapienza:

Per your request to Richard Abrams, Riley Power Inc (RPI) is pleased to furnish a budget proposal to CAMP DRESSER & McKEE INC for a cold end SCR system to be located in Hillsborough Florida. The indicative proposal for this unit has the following equipment to reduce the emissions from 270 ppm to 50 ppm with a NH3 slip of 15 ppm and a catalyst life of 24,000 hours:

SCR Inlet Duct
SCR System start-up Bypass Duct (around the GAS to GAS heat exchanger)
SCR Outlet Duct
Gas to Gas heat exchanger
Bypass and Isolation Dampers with Seal Air Systems as required
Gas duct burners for flue gas temperature control
RPI Delta Wing® flue gas and reagent mixers
Reactor Casing and internals
Catalyst
Foundation information (loads) for all equipment furnished
Structural steel including all stairs, platforms, railing and ladders
Catalyst handling system of hoists, monorail system and loading carts
Solid Modeling for flue gas flow analysis
Aqua ammonia storage system including two storage tanks, each with the capacity of holding one truck volume (one for system operation and one for truck unloading, with truck unloading connections.
Ammonia delivery system from the tank farm to the SCR inlet duct utilizing skid mounted pumps and direct injection nozzles.
Complete controls system including engineering for draft controls for the SCR Bypass Damper system
Complete Field Instruments for control on the reactor including inlet NOx Analyzers. Final NOx control will be by the CEMS monitor on the stack.
Training program for operators and Maintenance Personal
Ammonia leak detectors in the ammonia storage facility and the direct injection control valve locations
RPI will furnish electrical loads, compressed air , water, steam, and auxiliary fuel requirements at the battery limits

Items not included in material pricing

Ductwork from the boiler to the Gas heat exchanger isolation and bypass dampers; and from the gas heater isolation dampers to the ID fan inlet.
Labor and erection equipment for the installation of the proposed equipment and any modifications to existing structures.
Foundations and all Civil work
Electrical equipment including switchgear, MCC's, wire, conduit, cable trays, etc.
Upgrades to existing station's systems and services for utilitiesFire protection equipment
Safety equipment,
Building or enclosure
Wind load design into SCR, support steel and equipment. (Wind loads are to be handled by building enclosure and support steel separate from equipment support steel)

The footprint for this SCR will be approximately 30 feet square and approximately 50 feet high. This arrangement is based on the SCR directly above the gas to gas heat exchanger for a compact footprint.

The Indicative Material Price for the design, and supply of the SCR system as described above is Six Million Five Hundred Thousand Dollars ($6,500,000). This estimate is conservative and with additional data and the scope further defined, RPI expects the estimate to be reduced. As this project develops and a firm price will be provided, RPI will assist you in obtaining a construction estimate.

The other information you requested in your letter will be sent to you early nest week.

We look forward to a successful project working with CAMP DRESSER & McKEE to expand the facilities at the Hillsborough County Facility. If any additional questions arise during the review of the above, please feel free to contact me at (508) 854-3850, Fax(508) 854-3800 email: DMALONE@Babcockpower.COM or Richard Abrams at (508) 854-1140 email: RABRAMS@babcockpower.COM.

Sincerely,

Dennis M. Malone
Proposal Manager

Attachments:

Cc: Richard Abrams, Director, Proposals, Environmental Technology

Sapienza, Frank

From: Dirk_Eeraerts@keppelseghers.com
ent: Wednesday, July 13, 2005 5:39 PM
o: Sapienza, Frank
Subject: Re: FW: SCR for Hillsborough County

Dear Frank,

The revised budget estimate for the Hillsborough SCR system is US$ 5.9 million. This takes into account the capacity increase of approx. 15% and leaves out the installation. The scope is therefore reduced to equipment supply (all equipment + ducts + stairs and gangways) + supervision services during erection, commissioning and acceptance test. If we take out installation, we have to take out piping and cabling as well. For piping and cabling, supply and installation is part of one subcontract so I cannot separate installation only. Civil works are not included (were not included in the initial estimate).

Best Regards,
Dirk Eeraerts
Keppel Seghers Inc
1235 F Kennestone Circle, Marietta, Georgia 30066, USA
Tel: 770 421 1181 (ext 234), Fax: 770 421 8611

"Sapienza, Frank"
<SapienzaFC@cdm.c
om>
To: <Dirk_Eeraerts@segherskeppel.com>
cc:
Subject: FW: SCR for Hillsborough County
07/10/2005 09:24
PM

Dirk,

I have one correction to make in our request for an SCR system.
The flue gas flow to the SCR system I previously gave you was 126,141acfm at 270 degrees F.
This flow is the nominal or normal operating condition. However, the SCR system will have to be designed for the maximum flow condition of
145,149 acfm at 270 degrees F. Thanks,
ok forward to hearing from you.

Frank Sapienza

From: Dirk_Eeraerts@segherskeppel.com
[illegible]nt: Wednesday, February 16, 2005 6:35 PM
[illegible]: Sapienza, Frank
Cc: Ann_Raveel@segherskeppel.com; ivan_christiaens@segherskeppel.com; Stephane_Poellaer@segherskeppel.com; Wallace, Marc
Subject: RE: Hillsborough County SCR information

Frank,

Hereafter the SCR information:

1. Contact person at the Ivago facility in Gent, Belgium is Karel Matthys, phone: +32 9 2408159, e-mail: karel.matthijs@ivago.be

2. Budget estimate

We have based our budget estimate on the following design data :
Flue gas flow and analysis as per your letter dated November 30, 2004
NOx Concentration : inlet: 270 ppmdv @ 7% oxygen (396 mg/Nm3 dry 11%O2); stack: 70 mg/Nm3 dry 11%O2
Required Ammonia Limit : 15 ppmdv @ 7% oxygen (8.13 mg/Nm3 dry 11%O2) based on CEM quarterly average
SO2 max: 26 ppmdv at 7% oxygen (or 38 mg/Nm3 dry at 11% O2)
Flue gas temperature: 270 F (132 C)
Operating temperature: 230 - 250 C

We have based our budget estimate on the following scope:
re-heat based on combination of heat exchanger (flue gas / flue gas) and steam
out door installation, no civil works included in budget
ID fan only sized for pressure drop of SCR; main ID fan not included in budget
analyzers at inlet of SCR are included, stack analyzing equipment not included
No burners for regeneration (selected operating temperature avoids regeneration)
ducting, piping, insulation, stair, gangways, painting, electrical system are included
PLC based control system included
including construction, testing and commissioning, training of operators.
air compressor not included
spare parts not included

Total budget estimate for the above: US$ 7.4 million

[illegible]st Regards,
Dirk Eeraerts

SEGHERS Keppel Technology Inc
1235 F Kennestone Circle, Marietta, Georgia 30066, USA
Tel: 770 421 1181 (ext 234), Fax: 770 421 8611

BD Heat Recovery Division Inc.
7800 - 113th Street North, Suite 202
Seminole, FL. 33772

Phone 727-392-0492
Fax 727-391-9289

CDM
One Cambridge Place,
50 Hampshire Street
Cambridge, Massachusetts 02139

December 22, 2004

Attn: Mr. Frank C. Sapienza

Dear Frank:

Mr. Flemming Hansen of Haldor Topsoe has passed along your request for Selective Catalytic Reduction Information on Municipal Solid Waste Systems and we would like to take this opportunity to introduce ourselves to you and your client Hillsborough County. Previously we were the US arm of Balcke-Dürr GmbH (a member of the Deutsche Babcock group) located in Oberhausen, Germany and a designer and supplier of various systems and equipment to the Utility, Industrial and Petrochemical markets. Balcke-Dürr has undertaken a number of projects involving the addition of SCR units to MSW plants in Germany and other locations in Europe. Unfortunately in 2002 Deutsche Babcock became insolvent and various parts of the company were sold. The Energy group, which was responsible for the design and supply of the clean side SCR systems, was sold to GEA another large German Engineering Company and the US group became BD Heat Recovery.

The Compact DeNOx system was developed for use in the German waste to energy plants to remove NOx, dioxins and furans from low temperature gas streams. These selective catalytic systems are installed behind wet scrubbers and are designed to reheat the dirty gases prior to entering the catalyst. One advantage of the Compact DeNOx system is the low operating cost due to the high efficiency heat exchanger incorporated into the overall system.

In a typical waste to energy plant in Germany, the dirty flue gases enter the Compact DeNOx system (from the wet scrubber) at around 180°F. These gases are normally saturated and are therefore preheated (usually with a small steam coil) up to about 230°F prior to entering the heat exchanger. Exiting from the high efficiency heat exchanger at approximately 600°F the dirty gases are increased to 650°F with a direct-fired burner (or steam coil) prior to the direct injection of aqueous ammonia (NH_4OH). Please note for dioxin and furan removal only, ammonia injection is not required.

To ensure full and complete mixing and homogenizing of the ammonia and NOx we utilize our propriety Static Gas Mixers this produces even gas distribution and temperature to the catalyst beds. The mixed flue gases flow through the catalyst where the NOx, dioxins and furans are converted.

The hot clean gases are then used by the high efficiency heat exchanger to preheat the cold dirty gases. The clean gases then exit to the atmosphere at around 240°F.

The proper distribution and mixing of the dirty gases is essential to the optimum performance of the catalyst and in the case of NOx removal greatly assists in keeping ammonia slip to a minimum. Our experience has shown that it is virtually impossible to flow model these systems using computer simulation, consequently we always produce a scale model to design and position the static gas mixers and homogenizers. This also allows our clients to become assured that the system will perform as expected before it is even constructed.

In the US we have supplied eight of these systems (although not on MSW plants) two units are operating in downtown Boston at the Distrigas LNG facility (5 ppm NOx and 5 ppm ammonia slip), four units removing Dioxins from VCM plants for Oxychem (two in Corpus Christie and two in Deer Park, Texas). Two units are in the process of commissioning and start-up at the Clean Harbors hazardous waste facility in Deer Park, Texas. In all these US plants we have used Haldor Topsoe catalyst, the same catalyst is used for NOx and Dioxin removal however significantly more catalyst is required for the Dioxin.

Attached to this E-mail are the references for our SCR systems together with a separate excel sheet showing the flows, flue gas analysis and removal rates. Please note that most of the systems remove NOx and Dioxin but not all of them. We have also attached information showing some of the details of our system and other pertinent information.

With regard to the second part of your request we will be happy to provide you with some budgetary information however before we can proceed with this item we will need to know if a scrubber or wet ESP is expected to be part of the system. The design of the system will change based on the inlet temperature and saturation condition of the dirty gases. If the gases are saturated then we will need to provide a preheat section and a two stage heat exchanger with the cold end section usually manufactured from Hastalloy to resist the chloride corrosion found in MSW plants.

If the dirty gases are at a higher temperature and not saturated then typically a preheat section is not required and a single stage heat exchanger can generally meet the required efficiency while the materials of construction would normally be carbon steel.

We trust the enclosed information meets your immediate requirements and look forward to discussing our significant operating experience with you in the near future.

Sincerely Yours,

David Hawkins

Sapienza, Frank

From: Dave Hawkins [djh@bdheat.com]
Sent: Wednesday, December 22, 2004 5:29 PM
To: Sapienza, Frank
Subject: Fw: SCR Systems for Waste to Energy Plants

----- Original Message -----
From: Dave Hawkins
To: Frank C. Sapienza
Cc: Tom Ryan ; Flemming Hansen ; Mark Wallace
Sent: Wednesday, December 22, 2004 4:18 PM
Subject: SCR Systems for Waste to Energy Plants

Dear Frank:

Flemming Hansen of Haldor Topsoe forwarded your request for information on SCR systems operating with MSW plants. Please find attached a letter of Introduction plus product literature, references and operating details. For further information please see our website www.bdheat.com

Please note we will be closed for the Holidays from December 24 and reopen January 3, 2005

Best Regards

Dave Hawkins

BD Heat Recovery Div.

Phone 727-392-0492
Fax 727-391-9289
E-mail djh@bdheat.com

BD Heat Recovery Division Inc.
7800 - 113th Street North, Suite 202
Seminole, FL. 33772

Phone 727-392-0492
Fax 727-391-9289

February 25, 2005

Mr. Frank C. Sapienza
Camp Dresser & Mckee, Inc.
50 Hampshire Street
Cambridge, MA. 02139

Dear Frank:

Please find enclosed our budgetary proposal for the supply of One Compact DeNOx Systems for the proposed Covanta 600 TPD Waste to Energy Plant in Hillsborough County, Florida.

We have based the design on a stack NOx emission of 27-ppmdv @ 7% O_2, which is a reduction of 90% compared to the inlet operating conditions of 270-ppmdv @ 7% O_2 with a maximum of 15-ppm ammonia slip.

The inlet gas temperature is high enough that we would not expect corrosion to be an issue with the heat exchanger however it is possible that ammonia bisulfate and/or ammonia sulfate could form on the heating surfaces. Should this be the case then off-line water washing would be required to clean the surfaces, depending on the frequency of washing corrosion could occur if carbon steel is used for the plate material.

We have assumed that the NOx measuring equipment would be in our scope, however this can be omitted should this be the preferred situation. However, the NOx inlet and outlet information is required to calculate the amount of ammonia injection. We have therefore assumed that this programming information supplied by BD Heat would be placed in the clients DCS system.

We trust the enclosed information meets your immediate requirements, but should you need any additional information or clarification, please do not hesitate to contact us.

Sincerely Yours,

David Hawkins

I. Introduction

With over a hundred years of experience in the industrial and power markets, BD Heat Recovery Division in combination with GEA Ecoflex has the stability, ingenuity and resources to handle the most challenging gas-to-gas heat exchanger applications.

The Compact DeNOx system utilizes the beneficial characteristics of separate and uncontaminated gas streams. This combined with its highly efficient counter flow heat exchanger design; make it ideal for solving the problems associated with NOx removal from low temperature gases

II. A. Product Description

The Compact DeNOx system is a clean side SCR (Selective Catalytic Reduction) system specifically designed to allow the removal of NOx from cold gases while using a minimum of energy to reheat the gases to the optimum catalyst temperature.

A newly installed induced draft fan (supplied by others) transmits the cold dirty flue gases from the fabric filter system to the Compact DeNOx system. The High Efficiency Heat Exchanger (HEHE) is a single-stage counter flow plate-type recuperator. The heating surface consists of shaped plates, which are welded together and assembled into heat exchanger modules.

The hot and cold gases flow over the plates in counter flow to one another, producing a smooth temperature curve and eliminating the typical diagonal profiles occurring in cross flow exchangers. The welded shaped plates guarantee a high thermal efficiency, while maintaining the gases separate from each other, ensuring uncontaminated and leak free operation.

The heat transfer plates are manufactured out of various steels, selected based on the gas constituents and temperature range. The types of fuel being fired and the expected operating conditions determine the plate gap and profile.

Heat transfer plates are welded together to form plate packs. These plate packs are assembled into modules, which when assembled on site produce the HEHE.

The dirty gases after leaving the heat exchanger at around 600°F are mixed by a static gas mixer with additional heat supplied by a burner installed in the Compact DeNOx systems casing. The gas temperature is increased to approximately 650°F, which is an optimum temperature for the catalyst to operate.

A 19% ammonia solution (NH_4OH) is injected into the hot dirty gas stream and homogenized with an additional SGM prior to turning through 180° and entering the SCR DeNOx catalyst where the NOx reacts with the ammonia and the catalyst to form water and nitrogen.

The clean hot gases then pass downward through the High Efficiency Heat Exchanger and heat the dirty cold gases. The cooled clean gases are then discharged to the atmosphere via a stack.

B. Control Philosophy

Prior to the ammonia injection point additional heat will be added via a burner to increase the dirty flue gases from approximately 600°F to 650°F. Temperature indicators will monitor the dirty flue gas temperature prior to the HEHE and catalyst and will adjust the burner-firing rate to maintain the inlet temperature to the catalyst.

The NO_x content of the flue gases prior to entering the catalyst is monitored, this value in conjunction with the flue gas flow (input supplied from a flow meter) will then control the amount of NH_4OH injected into the dirty flue gas stream. Additionally the NOx content of the clean flue gas is measured and this value provides a feedback loop to the ammonia injection control valve.

Ammonia slip at the flue gas outlet can be monitored however this will not be used for control. Experience indicates that the accuracy of these devises at the levels required is unreliable and should not be used for control purposes. Typically the slip is calculated using the outlet NOx compared with the amount of ammonia injection and comparing these two values with the calculated injection rates.

C. Start-Up

It is envisioned that the Compact DeNOx system will be started using fresh air supplied by the induced draft fan. Heat will be added to the system by the natural gas burners installed in the system, once the Compact DeNOx system is at the operating temperature then the dirty gas will be slowly admitted to the system at a rate that will maintain the catalyst temperature in the normal operating range.

D. Haldor Topsoe Catalyst Information

Parameter	15 ppm slip
Catalyst Type	DNX-930
Volume per Unit (m^3)	18.46
Number of Layers	1 + 1 spare
Number of Modules per layer	108
Nominal Module Size (mm) HxWxL	586x466x466
Module Arrangement	12 x 9
Reactor Dimensions (ft) W x L	18.5 x 13.8
Weight of each F type Module (lbs)	120
Total Weight (lbs)	12,960

System Operating Costs

The single-stage heat exchanger produces an approach temperature (hot gas - cold gas) of 50°F. At the design load this requires a natural gas usage of approximately 9,800 SCFH. Assuming a fuel cost of US $5.50/million Btu and a yearly operation of 8,000 hours the operating cost for one unit would be: 8.8 x 5.50 x 8,000 = $387,200.

III. Scope of Supply

A. Compact DeNOx System

BD Heat Recovery will supply One (1) Compact DeNOx Systems each incorporating a high efficiency heat exchanger size C-6-6.5-2978-S-6W. The system will consist of: -

- Engineering including P&ID and logic diagrams, design and flow modeling of Compact DeNOx System
- Heat transfer plates manufactured from carbon steel
- All casings manufactured from 1/4" carbon steel
- Lower & upper distribution hood manufactured from Carbon Steel
- Fabric expansion joint by Papco or equal with 1000I Texflex material
- Static Gas Mixers and necessary guide vanes
- Ammonia Injection lances and nozzles complete with manual adjustment valves and flow meters for the aqueous ammonia and atomizing air
- SCR Catalyst housing from 1/4" carbon steel
- SCR Catalyst
- Galvanized structural steel from grade level up to the Compact DeNox integral support structure
- Platforms, ladders and handrails to provide operating and maintenance access
- Factory assembly of heat exchanger into three modules.
- Assembly of system casings into road transportable sections
- Burner heating System (see details below)
- Delivery to Hillsborough County Job Site, Florida

B. Burner System

Shell - The heater shell is a 1/4" stainless steel 304 shell with structural stiffeners. The shell features three (3) wall mounted main burners and pilot peepsight, reinforced valve train mounts, elevated ignition transformer mount and terminal enclosure, downstream pressure taps with cocks and hose barbs and flanged inlet and outlet duct connections.

Burners – Each is an Eclipse-Winnox gun style burner and features an integral pilot that assures reliable light off by spark ignition and flame monitoring by UV scanner. The burner is complete with valve train and electric spark ignition.

Combustion Blower - is an industrial duty New York Blower Co. centrifugal fan. The fan is constructed of painted carbon steel and is complete with filter; TEFC motor; belt; shaft and bearing guards; clean out door and drain. Brake horsepower of fan is approximately 100 hp.

Valve Train - the gas valve train features

Inlet gas cock
Main gas pressure regulator
Pressure gauge
High gas pressure switch
Low gas pressure switch
Dual safety shutoff valves with actuators
Vent valve
Air/Gas control valve with pneumatic actuator, valve modulation is by a 4 -20mA control signal

The gas train is prepiped and prewired to a terminal strip mounted in a NEMA 4 enclosure.

Control Panel - is a NEMA 4 enclosure featuring:

Three (3) Honeywell series flame relay with annunciator and door-mounted display
Appropriate relays and breakers
Start/stop buttons
Indicator lights
One (1) high temperature alarm
One (1) temperature controller.

All electrical components are heavy-duty industrial quality of the Square D / Allen Bradley genre. Wire is THHN and conduit is rigid and seal tight. All wires are numbered to match the wiring diagram line numbers and all terminals are numbered.

Ratings:

Burner Maximum Input	28.0 x 10^6 Btu/hr
Burner Design Input	8.8 x 10^6 Btu/hr
Burner Min Input	3 x 10^6 Btu/hr
Estimated NO_x	<30 ppm corrected to 3% O_2
Maximum CO	<100 ppm corrected to 3% O_2
Valve Train	IRI
Local Enclosure	NEMA 4
Remote Enclosure	NEMA 4

The burners are designed to permit the flue gas temperature going to the catalyst to be increased by 100°F to permit the removal of any ammonia bisulfate that maybe formed in the catalyst. The over-fire condition will also allow the unit to be brought on-line in a shorter time frame.

C. Assembly

Each heat exchanger would be delivered to site as four modules, each weighing approximately 98,000 lbs. The rest of the equipment would be shipped to site in large road transportable pieces.

D. Instrumentation & NOx Analyzers

- Instrumentation as follows designed to class 1, division II
  J type thermocouples by Omega or equal
  Pressure indicators and transmitters by Omega or equal
  Local dial pressure gauges by Shelby Jones or equal

- Chemiluminescence NOx and NH_3 (outlet only) Analyzers located at the dirty gas inlet and the clean gas outlet designed to class 1 division II.

  The analyzer system will contain the following equipment:
  Thermoelectric water condenser complete with a dual-headed peristaltic pump for continuous drain and moisture sensor to indicate carryover.
  Multi-stage filtration
  Stainless steel sample transportation pump
  The following component manufacturers have been used in preparing this quotation, however we reserve the right to change suppliers:
  Sample Probe / Filter - Rosemount or equal
  Ball valves - Grove
  Glass fiber filters - Porous media, Balston or equal
  Solenoid valves - Parker, Asco or equal
  Fittings - Gyrolok
  Diaphragm pumps - Air Dimensions or equal
  Flow meters - Matheson, Aalborg or equal
  Sample coolers/condensers - Universal Analyzers or equal
- The analyzers and sample handling equipment will be fully mounted, piped and wired in a free standing NEMA 7 enclosure.
- Oxygen Analyzer
- Local flow meters by Omega on individual ammonia nozzle lines

E. Leakage

The welded design of the heat transfer plates maintains the gas and air streams separate and leak free. Every individual plate pack is tested with compressed air prior to leaving the fabrication shop in Germany. The plate packs are guaranteed with a leakage rate during testing of 0.1% (gaskets used during testing allow a small amount of leakage).

After erection of the Compact DeNO$_x$ system a florescent dust test (as detailed below) should be carried out over the entire system to ensure that there are no leaks in the sealing welds separating the clean and dirty gases.

1) Prior to start-up of the blower at low speed the completed Compact DeNOx system should be thoroughly cleaned and inspected.
2) Blanking materials will be installed at the clean gas inlet to the lower distribution hood to prevent the passage of florescent dust.
3) The blower is started a minimum speed/pressure and the powder (DayGlo T 11 Synthetic Organic Colorant) is added to the suction side. If the use of the blower is not available or desirable than a temporary fan should be installed in the ducting.
4) All joints and seal welds are inspected using a black light particularly the seal welds around the high efficiency heat exchanger to ensure zero leaks between the clean and dirty gases.
5) Areas need repair are clearly visible under the black light and are marked for repair.

F. Codes

The High Efficiency Heat Exchanger is a low-pressure exchanger and will not comply with any pressure vessel codes.

Except for pressure related items covered by ASME pressure codes our selected fabricators will provide welding Procedure Specifications (WPS) and Welder Qualifications (WQ).

Welding procedures and welders will be qualified per the requirements of AWS D1.1 for the materials and positions required. Visual inspection of welds shall comply with AWS B1.11.

Welding in Germany will be as follows:
Qualifications Din 8560
Weld Filler material Din 18800/1

Materials will comply with the following:

1) Carbon Steel to ASTM A36
2) Corten Steel to ASTM A588
3) Stainless Steel to ASTM A240

G. Surface Preparation & Painting

All external module and distribution casing surfaces and structural steel beams will be sand blasted per SSPC-SP6 and primed with one coat of Carbo zinc 11 primer 2-3 mils thick. All casing surfaces are covered with insulation and no additional painting is required on site.

H. Exclusions

The Scope of supply does not include the following items, unless specifically included in our proposal:

- Support structures other than specified
- Cleaning equipment
- Site Work and Erection
- Site Insulation
- Anchor bolts
- Federal or local sales or usage tax

- Equipment Required by Customer for NOx Analyzers
  - Clean and dry location for the NOx Analyzers
  - 120 VAC, 50/60 Hz single phase power
  - Zero and span calibration gas cylinders and regulators
  - Heat-traced sample line, fittings, cable and conduit required for installation of the system
  - Clean dry instrument air at 80 -100 psig to blow-back sample port
  - Cylinder of ozonator air for NOx analyzer
  - Atmospheric vent location for system exhaust

IV. Commercial Terms

The prices quoted for our Scope of Supply as defined in section III are budgetary.

A.1 Price For One (1) Compact DeNOx Systems

Price as detailed in our scope of supply section III F.O.B. Hillsborough County, Job Site, Florida:

US $3,100,000 (Three million one hundred thousand US Dollars)

A.2 Commissioning & Start-Up Service

BD Heat Recovery can provide commissioning and start-up assistance and training by qualified field personnel at a daily rate of US $950 per 8-hour day plus travel time at $70/hr and expenses. Assistance and travel on Saturdays and over 8 hr. days billable at time and a half. Assistance and travel on Sundays, holidays, over 8 hours on Saturdays and over 16 hours on weekdays are charged at double time. Living expenses include lodging, meals, plane tickets, rental cars and personal vehicle use ($0.35/mile).

B. Typical Payment Schedule for Equipment Supply

5% on submittal of General Arrangement Drawings
20% on receipt of heat exchanger plate materials at fabrication shop
25% on completion of plate packs for the heat exchanger
45% on notification of readiness for delivery for the balance of the equipment for the first system (excluding catalyst))
5% on delivery of catalyst to job site

All Payments are net 30 days

C. Validity

The prices quoted are budgetary and non-binding.

D. Terms and Conditions

To be negotiated

E. Delivery

Our normal delivery would be 44 weeks from receipt of purchase order.

The catalyst would be delivered later after the erection of the equipment is completed.

The following time frames from date of order (unless otherwise specified) apply to the delivery of Drawings and Documentation:

G.A. drawings	5 weeks
Preliminary Fabrication Schedule	5 weeks
P & ID Diagram	12 weeks
Shop Fabrication Drawings	12 weeks
Structural Steel Drawings	12 weeks
Installation Erection Drawings	24 weeks
Material Test Certificates (Plates)	4 weeks after completion of plate packs
Other applicable material Test Certificates	During manufacture
Inspection Procedures	6 weeks
Operating manual	2 weeks prior to delivery
Recommended Operating Spares List	20 weeks
Packing & Shipping List	At time of shipment
Erection and Installation Procedures	24 weeks

H. Guarantees (Typical)

Based on the following dirty flue gas conditions and as per detailed in the specification:

Base Case	
Fuel	As per specification
Gas Flow	390,880 lbs/hr
Gas Temperature	270°F
Pressure	-20"WC
Inlet NOx	270 ppmvd @ 7% O_2
O_2	5.57% wet vol.
H_2O	28.01% wet vol.
CO_2	8.89% wet vol.
N_2	56.83% wet vol.
Inlet SOx	26 ppmvd @ 7% O_2

Table 1 Flue Gas Data

It is assumed that 2 - 5% of the inlet NOx is present as NO_2 and 10% of the SOx is present as SO_3.

Based on the above assumptions, the dew point of the ammonia bisulfate (ABS) in the catalyst is approximately 500°F, and it is therefore not feasible to continuously operate below this temperature. Should ammonia bisulfate precipitate out on the catalyst this can be removed by operating above the dew point for a period of time.

BD Heat Recovery will Guarantee the following outlet conditions based on an hourly average (assumes BD Heat Recovery purchases the Catalyst).

	Base Case
NH_3 Slip, ppmvd @ 15% O_2	15
NO_x Outlet @ 7% O_2	27 ppmdv
SO_2 Oxidation, %	0.5
NH_3 Consumption per Unit, (19% Aqueous NH_3)	260 lbs/hr

Table 2

The SCR catalyst volumes are designed for maximum NH_3 slip as specified above and during steady state conditions is achievable. However, during sudden load changes minor overshooting may occur.

Expected Catalyst Lifetime

Based on the operating conditions no less favorable than those listed in Table 1 BD Heat Recovery will guarantee the performance as listed in Table 2 for a period of 18,000 hours of operation, but no longer than 60 months from date of delivery.

System Pressure Drop

Based on operating conditions as outlined in Table 1 (base design) with a dirty gas inlet temperature of 270°F; BD Heat recovery will guarantee a pressure drop across the system from the inlet flange of our scope of supply to the outlet flange of 12" WC.

All guarantees are based on a performance test to be conducted by the owner and witnessed (without cost to the owner) by BD Heat Recovery Div. All other costs associated with this performance test are solely the obligation of the owner.

I. Limitations / Catalyst Poisons

The guarantees offered are subject to the catalyst being loaded and operated in accordance with the manufacturers recommendations.

There are several potential poisons to the SCR catalyst. In a natural gas application there is normally no poisoning of any significance however, there could be various contaminates that could shorten the life of the catalyst. These poisons would primarily be metals such as sodium, potassium, arsenic, and phosphate. Additionally any washing of the catalyst could be detrimental.

COMPACT De NO$_x$ DATA SHEET

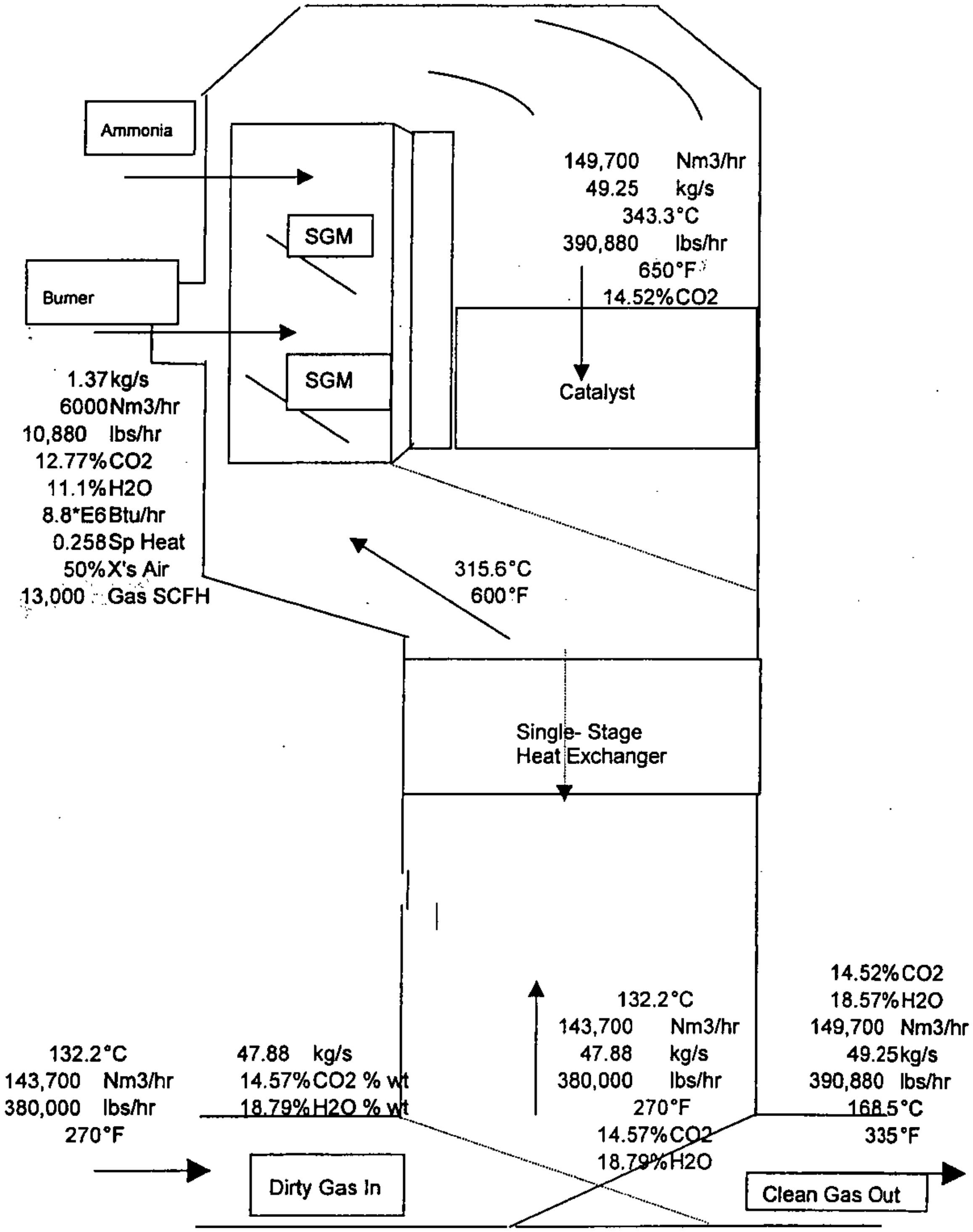
Exchanger Size C-6-6.5-2978-S-6W

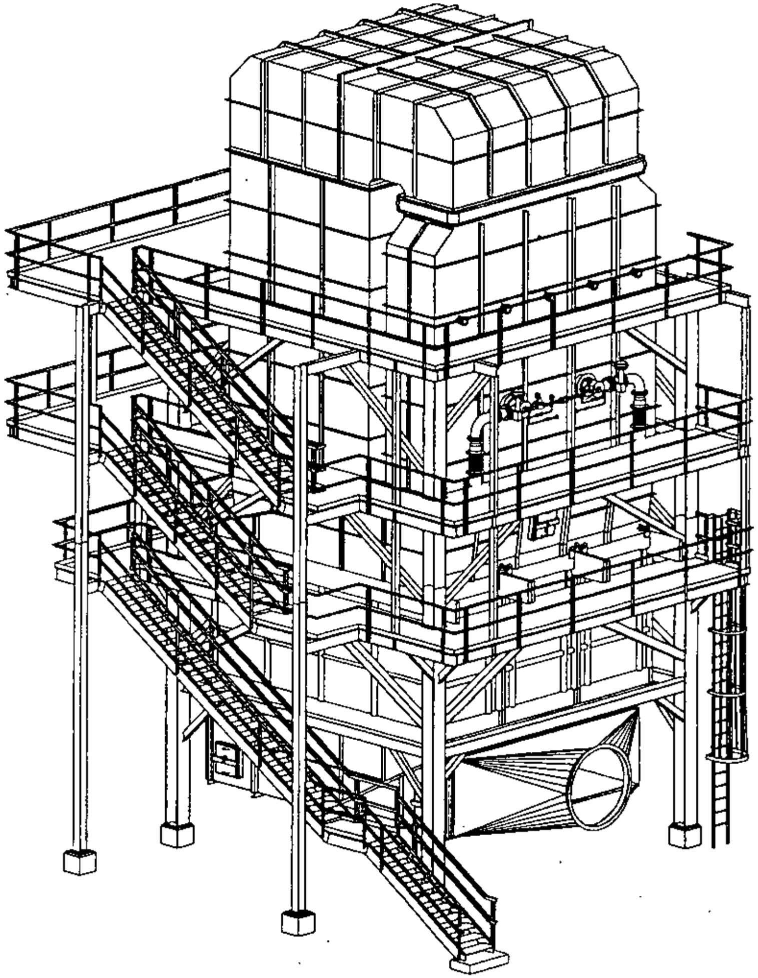
	Design
Clean Gas Flow (lb./hr)	390,880
Clean Gas Inlet Temperature (°F)	650
Clean Gas Outlet Temperature (°F)	335
Dirty Gas Flow (lb./hr)	380,000
Dirty Gas Inlet Temperature (°F)	270
Dirty Gas Outlet Temperature (°F)	600
Burner Flue Gas Flow (lbs./hr)	10,880
Gas Temperature to Catalyst	600
Burner Heat Input (Btu/hr x 10^6)	8.8
Overall System Pressure Drop	12
Heat Exchanged (Btu/hr x 10^6)	36.0
Heating Surface (ft^2)	193,880

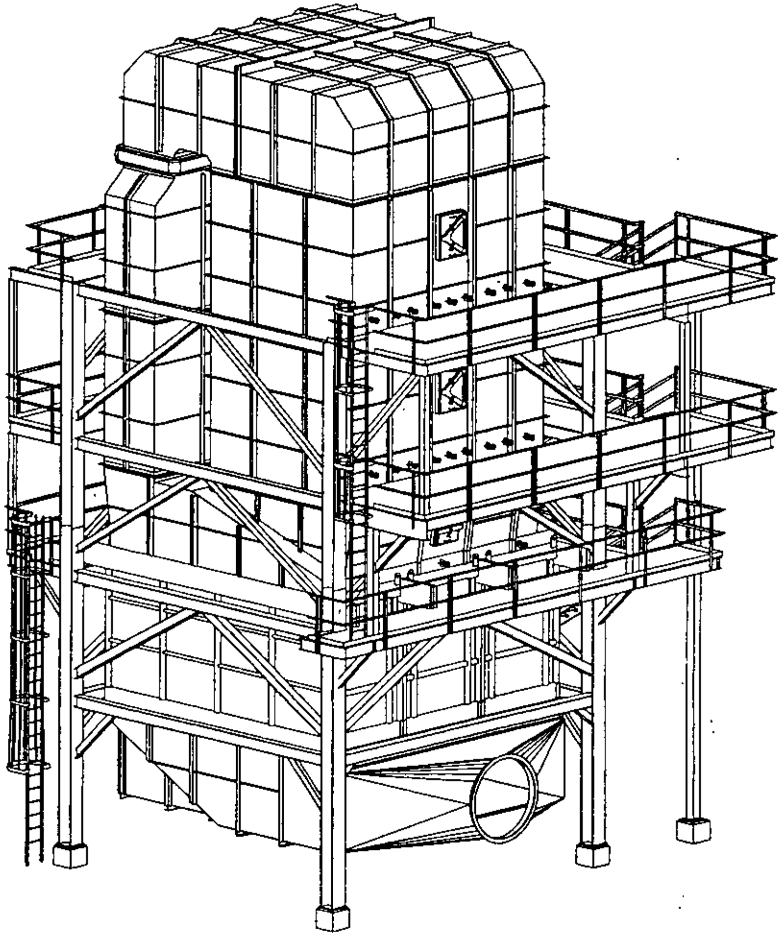
Mechanical Data

Plate Height (mm)	2978
Plate Thickness (mm)	0.8
Plate Gap (mm)	6.0
Plate Material	Carbon Steel
Estimated System Weight (Tons)	180

Base Design


Ammonia
Burner
SGM
SGM
149,700 Nm3/hr
49.25 kg/s
343.3°C
390,880 lbs/hr
650°F
14.52%CO2
Catalyst
1.37kg/s
6000Nm3/hr
10,880 lbs/hr
12.77%CO2
11.1%H2O
8.8*E6Btu/hr
0.258Sp Heat
50%X's Air
13,000 Gas SCFH
315.6°C
600°F
Single- Stage
Heat Exchanger
132.2°C
143,700 Nm3/hr
380,000 lbs/hr
270°F
47.88 kg/s
14.57%CO2 % wt
18.79%H2O % wt
Dirty Gas In
132.2°C
143,700 Nm3/hr
47.88 kg/s
380,000 lbs/hr
270°F
14.57%CO2
18.79%H2O
14.52%CO2
18.57%H2O
149,700 Nm3/hr
49.25kg/s
390,880 lbs/hr
168.5°C
335°F
Clean Gas Out





NO.	DATE	BY	APPD	REVISION	NO.	DATE	BY	APPD	REVISION	ISSUED FOR	DATE	BY	ISSUED FOR	DATE	BY
													PROPOSAL	02/17/05	JAC

COMPACT DENOX SYSTEM
C-6-6.5-2978-S-6W
COM FOR HILLSBOROUGH COUNTY
HILLSBOROUGH COUNTY

BD HEAT RECOVERY DIV., INC# 05-1005

BD HEAT RECOVERY DIV., INC

DRAWING TITLE: PROPOSED GENERAL ARRANGEMENT
ISOMETRIC VIEWS

DRAWN JAF	DATE 02/17/05	REV	DWG. NO.
CHECKED DT	DATE 02/17/05	A	PGA1
APPRVD JAC	DATE 02/17/05		
SCALE AS NOTED	DWG SIZE 24x36		

ALSTOM

Power
Environmental Control Systems Division

February 28, 2005

Camp Dresser & McKee Inc.
50 Hampshire Street
Cambridge, MA 02139

Attn: Mr. Frank Sapienza
Principle Engineer

Subject:: Request for Selective Catalytic Reduction Information

Dear Mr. Sapienza:

ALSTOM is please to respond to your inquiry for an SCR in support of the Hillsborough County WTE permitting process. We would like to start by addressing the questions which you have.

- Guaranteed NOx Emission Limit (to be confirmed in performance test) @ 525 degrees F. > 90% NOx reduction
- Ammonia slip > 15 ppmvd @ 7% Oxygen
- Catalyst volume > 13.90 cubic meters
- Expected catalyst life > 40,000 hours +
- Catalyst composition and minimum temperature required to achieve stated NOx reduction > Vanadium based catalyst operating at 525 degrees F. due to sulfur content
- Catalyst material used to control NH3 emissions > Vanadium based catalyst operating at 525 degrees F
- Catalyst replacement cost > US$122,000, Ex Works
- Approximate dimensions of SCR system > 12.3' x 12.4'
- Utility Requirements (natural gas, urea, power) > temperature of gas to be at 525 degrees F (by others), 800 kW/hr (pumps & vaporizer), pressure drop of 2-3 in. w.c., dependant on final duct arrangement, 35 lbs/hr ammonia usage (25% aqueous)

1409 Centerpoint Blvd.
Knoxville, TN (USA) 37932-1962
Tel : 865 693-7550
Fax 865 694-5203
www.power.alstom.com

- Lastly, the analysis requires that we estimate what the NOx permit limit should be for the fourth MWC with SCR control (currently 3 units installed, with a fourth to be added). The NOx permit limit is the outlet NOx concentration which can not be exceeded on a 12-month rolling average basis. We obviously can not require you to guarantee a long-term limit. However, as a surrogate, we are asking for guaranteed daily average NOx and NH3 limits which must be achieved for the duration of a two week continuous performance test > A NOx reduction of 90% @ ammonia slip of 15 ppmvdc could be reasonably expected, based on ammonia flow being correct, flue gas temperature being at or above 525 degrees F, gas and ammonia/ NOX distributions and gas composition and volume being consistently being met.

- As part of this submittal, you will find a separate file identifying ALSTOM's experience with SCR's at WTE facilities. You will note most are low dust installations in Europe, where this arrangement is more common than in North America, due to the cost of reheating the flue gas.

- Our Indicative estimate for the high dust SCR, including reactor, support steel, access, AIG, controls, and initial catalyst charge is $2,250,000, plus cost of installation,

If you require further assistance, please do not hesitate to contact either Noel Kuck or myself. Thank you for your interest in ALSTOM's products and services.

Very truly yours,

John Holbrook

John Holbrook
Global Power Sales
(o) 410-781-0383
(c) 410-274-5799
(e) john.Holbrook@power.alstom.com

cc: Noel Kuck
Business Applications Manager
(o) 865-694-5368
(e) noel.c.kuck@power.alstom.com

From: Jansen, Peter [Peter_Jansen@fwc.com]
[illegible]ent: Tuesday, February 15, 2005 3:23 PM
[illegible]o: Sapienza, Frank
Cc: Parham, David; Wagner, Dave
Subject: SCR for Hillsborough County Florida

Mr. Sapienza,

We are currently in the process of reviewing your Selective Catalytic Reduction (SCR) information request for the Hillsborough County Florida municipal waste incinerator project. While Foster Wheeler (FW) does not have any direct experience with waste incinerator type SCR systems, we have designed, supplied and erected a multitude of other SCR systems for various fuels. With this type of application (waste incinerator), the focus is with selecting the proper catalyst to handle this type of fuel. The ammonia system, whether it is anhydrous, aqueous or urea based will be configured for your particular project.

With this in mind, we will require additional data to enable us to obtain the requested information from catalyst vendors. Please provide the following:

1. Fuel analysis.

2. Ash Analysis.

[illegible] Trace Elements.

4. Required Outlet NOx.

4. Catalyst location: what equipment is located downstream of the SCR catalyst?

5. Temperature range: flue gas temperatures are a critical element in the selection of the catalyst, the information provided in your request suggests the temperature will range from 220 °F minimum to 270 °F. Is this the full range of temperatures the catalyst will be exposed to? Generally, a minimum flue gas temperature of 600°F is required for this type of sulfur bearing fuel.

6. Is there a SO2 oxidation requirement?

With the aforementioned information we can contact various catalyst suppliers and begin preliminary proposal development.

FW is willing to prepare an SCR system proposal for Hillsborough on a reimbursable basis with the agreement that FW would be awarded the work in the event the project moves ahead. Proposal costs would be deducted from the resulting contract price in the event of an award.

Sincerely,

Pete Jansen

Sapienza, Frank

From: Reed Robert [Robert.Reed@argillon.com]
Sent: Tuesday, February 08, 2005 3:04 PM
[illegible] Sapienza, Frank
Subject: RE: SCR Sytem for Hillsborough County, Fl

Frank,

I have attached a reference list of "Special Applications" for which we have supplied catalyst. It includes a number of waste ncinerators. It does not have the level of detail that you are requesting, however it's what I can offer at this time. I have checked vith our systems group regarding the budgetary quote for the system that you requested. They are not currently quoting systems or this application. If you find another company willing to quote the system, I would be happy to provide you with a budgetary uotation for the catalyst. If this is something you are interested in, I will need the following information:
Gas temperature, composition, and flowrate after being reheated. The current temperature is far too low.
Geometric constraints for catalyst bank
Performance requirements (NOx reduction, allowable DP, allowable NH3 slip, SO2 conversion limits (if any), any others)
Detailed gas analysis including any potential catalyst poisons

f you are interested in the catalyst quote, please get me the information above and I'll pull a design together.

egards,
ob Reed

obert R. Reed
gillon LLC
l: (678) 341-7521 (NEW)
[illegible]) 341-7509 (NEW)
nail: robert.reed@argillon.com (NEW)

---Original Message-----
rom: Sapienza, Frank [mailto:SapienzaFC@cdm.com]
ent: Tuesday, February 01, 2005 4:06 PM
: Robert.Reed@argillon.com
bject: SCR Sytem for Hillsborough County, Fl

Dear Mr. Reed,

Good talking with you today. I remember meeting with Bob Johnson and hearing his presentation on Siemens/Argillon's SCR capabilities which I was very impessed with.

The attached request-for-proposal letter describes the Hillsborough County, Florida project and the information we are requesting. Do hope to hear from Argillon on this interesting project.

Yours truly,

Frank Sapienza
Principal Engineer
Camp Dresser & McKee Inc.
[illegible]0 Hampshire Street
Cambridge, MA 02139
Phone: 617-452-6239
Fax: 617-452-8239

ARGILLON

Reference List - SINOx® Systems

Exhaust Gas Treatment Plants and Systems for Special Applications

No.	Customer/Operator	Country	Field of Application	Fuel	Capacity in kW	Volume flow in Nm^3/h	Extent of Delivery	Delivery Date
12	LAB/ Taejeon	F Korea	Waste Incineration	Municipal Waste	—	73,525	SINOx®	1997
13	LAB/ Tadaepo	F	Waste Incineration	Municipal Waste	—	57,619	SINOx®	1997
14	ENETEX Electro melting plant Kempten	D	Production process	tailgas	—	2,900	SINOx®	1997
15	MSE	USA	Ammunition Destruction	—	—	469	SINOx®	1998
16	TERAG Panofina	CH	Boiler Boiler	Gas Gas	— —	— —	SINOx® and Oxi- Cat SINOx® and Oxi- Cat	1998 1998
17	Siemens/ SBA Fürth	D	Waste Incineration Waste Incineration	Gas Gas	—	8,900 8,900	SINOx® SINOx®	1998 1998
18	ENETEX	D	Ammunition Destruction	—	—	—	SINOx®	2002
	Total SCR Systems:	**21**						

ARGILLON

Reference List - SINOx® Systems

Exhaust Gas Treatment Plants and Systems for Special Applications

No.	Customer/Operator	Country	Field of Application	Fuel	Capacity in kW	Volume flow in Nm^3/h	Extent of Delivery	Delivery Date
1	Sulzer Industries Du Pont de Nemours	F	Comustion of Production Residues	---	---	25,000	SINOx®	1992
2	Espindesa	E	Slag Decontamination	---	---	4,600	SINOx®	1994
3	Babcock BSH/ Leuna Werke	D	Chemical Process Exhaust	---	---	1,335	SINOx®	1994
4	Noell-KRC/ Wolff Walsrode	D	Cellulose Nitrifaction	---	---	6,170	SINOx®	1994
5	Faserwerk Kehlheim	D	Chemical Process Exhaust	---	---	4,400 4,400	SINOx® SINOx®	1994 1994
6	Forschungszentrum Karlsruhe	D	Waste Incineration	Waste	---	1,500	SINOx®	1994
7	Leybold Didactic	D	Distribution of Didactic Materials	---	---	---	SINOx®	1994 - 1995
8	Alsachimie (Rhone-Pulenc)	F	Combustion of Production Residues	Process Tail Gas/ HFO	---	112,000	SINOx®	1995
9	E.S.T.	D	Ammunition Destruction	---	---	---	SINOx®	1996

From: Pliska,Kevin [Kevin_Pliska@CovantaEnergy.com]
[illegible]t: Wednesday, July 06, 2005 9:31 AM
To: Sapienza, Frank
Cc: Treshler,Joseph
Subject: RE: SNCR for Hillsborough

Frank,

The budget price we received from Fuel Tech in the fall of 2004 was $1,021,600. We have applied CPI escalation to this budget price to bring the April '05 budget price in at $1,044,684.

Please let me know if you need additional information.

Kevin

> -----Original Message-----
> **From:** Sapienza, Frank [mailto:SapienzaFC@cdm.com]
> **Sent:** Tuesday, July 05, 2005 11:52 AM
> **To:** Pliska,Kevin
> **Subject:** SNCR for Hillsborough
>
> Kevin,
>
> I am working on the Hillsborough County proposed Waste to Energy Facility, specifically I am preparing the Best Available Control Technology (BACT) evaluation. I am confirming some of our cost estimates at this point. Could you please supply us with the cost of the SNCR system proposed for Hillsborough's fourth combustion unit. We do not need the installed cost just the cost for the supply of the SNCR equipment. I was involved with the Hillsborough spec reviews which CDM performed so I am familiar with the system.
>
> The cost we are requesting is basically the scope of supply which Fuel Tech is providing for their NOxOUT Process. Specifically, Fuel Tech's scope includes:
>
> - One 15,000 gallon NOxOUT Reagent Storage Tank
> - One Circulation Module
> - One Redundant Metering Module
> - 3 Distribution Modules
> - 21 Wall Injector Assemblies
> - One Furnace Temperature Monitor
> - One Control Room Interface (PC-PLC based control system)
> - Engineering, Drawings, O&M Manuals by Fuel Tech
>
> I could use this cost information as soon as possible, within a day or two.
>
> Thank you,
>
> Frank Sapienza
> CDM
> Cambridge, MA
> tel: 617-452-6239
> e-mail: sapienzafc@cdm.com

Sapienza, Frank

From: Gorrie, Jason
[illegible]t: Thursday, February 10, 2005 3:00 PM
[illegible]: Sapienza, Frank; Hibbard, Cynthia; Wallace, Marc
Subject: FW: FGR $

From: Pliska,Kevin [mailto:Kevin_Pliska@CovantaEnergy.com]
Sent: Thursday, February 10, 2005 2:34 PM
To: Gorrie, Jason
Cc: Treshler,Joseph; Crellin, William; Strobridge, Daniel; Schneider,James
Subject: RE: FGR $

Jason,

Our boiler vendor has identified the approximate value of the proposed installed FGR system at $250,000.00. The split s approximately $200K material and $50K labor. Additionally, the APC vendor has estimated the installed component of the FGR duct in their scope at $27,700.

Please let me know if you require additional information in support of the permit application.

-----Original Message-----
From: Pliska,Kevin
Sent: Wednesday, February 09, 2005 11:21 AM
To: 'Gorrie, Jason'
Subject: FGR $

I have asked the vendors to breakout the equipment and labor costs.

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: Hillsborough County, Florida
2. Site Name: Hillsborough County Resource Recovery Facility
3. Facility Identification Number: 0570261
4. Facility Location
   Street Address or Other Locator: 350 N. Falkenburg Road
   City: Tampa County: Hillsborough Zip Code: 33619
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: Jason Gorrie, P.E.
2. Application Contact Mailing Address...
   Organization/Firm: CDM
   Street Address: 1715 N. Westshore Blvd., Suite 875
   City: Tampa State: FL Zip Code: 33607
3. Application Contact Telephone Numbers...
   Telephone: (813) 281-2900 ext. Fax: (813) 288-8787
4. Application Contact Email Address: gorriejm@cdm.com

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☒ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☒ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This application is being made under the provisions of the Florida Electrical Power Plant Siting Act

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
	Municipal Waste Combustor – Unit 4	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $ 125,000 (Power Plant Siting Act ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : Barry M. Boldissar

2. Owner/Authorized Representative Mailing Address...
Organization/Firm: Hillsborough County Solid Waste
Street Address: 601 E. Kennedy Blvd.
City: Tampa State: FL Zip Code: 33602

3. Owner/Authorized Representative Telephone Numbers...
Telephone: (813) 272 - 5680 ext. Fax: ( ) -

4. Owner/Authorized Representative Email Address:

5. Owner/Authorized Representative Statement:

I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

Signature

11/3/05
Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name: Barry M. Boldissar

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☒ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. (delegated)
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: Hillsborough County Solid Waste
   Street Address: 601 E. Kennedy Blvd.
   City: Tampa State: FL Zip Code: 33602

4. Application Responsible Official Telephone Numbers...
   Telephone: (813) 272 - 5680 ext. Fax: ( ) -

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature 11/3/05
   Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Jason M. Gorrie, P.E.
   Registration Number: 55341

2. Professional Engineer Mailing Address...
   Organization/Firm: CDM
   Street Address: 1715 N. Westshore, Suite 875
   City: Tampa State: FL Zip Code: 33607

3. Professional Engineer Telephone Numbers...
   Telephone: (813) 281 - 2900 ext. Fax: (813) 288 - 8787

4. Professional Engineer Email Address: gorriejm@cdm.com

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☑, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☑, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature

11/16/05
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 368.2 North (km) 3092.7		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 27/57/14 Longitude (DD/MM/SS) 82/40/22	
3. Governmental Facility Code:3	4. Facility Status Code:A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4953
7. Facility Comment :			

Facility Contact

1. Facility Contact Name:Glenn Hoag

2. Facility Contact Mailing Address...
Organization/Firm: Covanta Hillsborough, Inc.
Street Address: 350 Falkenburg Rd.
City: Tampa State: FL Zip Code: 33619

3. Facility Contact Telephone Numbers:
Telephone: (813) 684 - 5688 ext. Fax: ( ) -

4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name: Glenn Hoag

2. Facility Primary Responsible Official Mailing Address...
Organization/Firm: Covanta Hillsborough, Inc.
Street Address: 350 Falkenburg Rd
City: Tampa State: FL Zip Code: 33619

3. Facility Primary Responsible Official Telephone Numbers...
Telephone: ( ) - ext. Fax: ( ) -

4. Facility Primary Responsible Official Email Address:

FACILITY INFORMATION

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
SO2	A	N
NOx	A	N
CO	A	N
PM	A	N
PCDD/PCDF	A	N
Hg	A	N
Cd	A	N
Pb	A	N
HCl	A	N
HF	A	N
Ozone (as VOC)	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   ☒ Attached, Document ID: Vol. I ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification:
   ☒ Attached, Document ID: Vol. III, Section 3
3. Rule Applicability Analysis:
   ☒ Attached, Document ID: Vol. III, Section 2
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 4 ☐ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 4 ☐ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 5 ☐ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 5 ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 5 ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.):
   ☒ Attached, Document ID: Vol. III, Section 5 ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☒ Attached, Document ID: Volume III, Section 3 ☐ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
☒ Attached, Document ID: Volume II ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only):
☒ Attached, Document ID: Volume II ☐ Not Applicable (revision application)

2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought):
☒ Attached, Document ID: Volume III, Section 2
☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan (Required for all initial/revision/renewal applications):
☐ Attached, Document ID:________
Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only):
☐ Attached, Document ID:________
☒ Equipment/Activities On site but Not Required to be Individually Listed
☐ Not Applicable

5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) :
☐ Attached, Document ID:__________ ☒ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
☐ Attached, Document ID:__________ ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section: Municipal Waste Combustor, Unit 4

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code: C	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? ☐ Yes ☒ No

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
APC for the fourth unit will consist of a spray dryer absorber, fabric filter baghouse, activated carbon injection system, selective non-catalytic reduction system, and flue gas recirculation.

2. Control Device or Method Code(s): 016, 025, 048, 067, 107

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: 600 tpd of waste when HHV = 5000 Btu/lb
2. Maximum Production Rate:
3. Maximum Heat Input Rate: 288 million Btu/hr
4. Maximum Incineration Rate: 50,000 pounds/hr
   600 tons/day
5. Requested Maximum Operating Schedule:
   24 hours/day 7 days/week
   52 weeks/year 8760 hours/year
6. Operating Capacity/Schedule Comment:

MWC Unit No. 4 is rated at 600 tons per day of MSW with a reference higher heating value of 5,000 Btu/lb of waste on an annual basis.

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: existing stack	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

5. Discharge Type Code: V	6. Stack Height: 220 feet	7. Exit Diameter: 5.5 feet
8. Exit Temperature: 270 °F	9. Actual Volumetric Flow Rate: varies	10. Water Vapor: Varies

11. Maximum Dry Standard Flow Rate: Varies (see Vol. III, Section 6)	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: 17 East (km): 368.2 North (km): 3092.7	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) 27/57/16 Longitude (DD/MM/SS) 82/21/12

15. Emission Point Comment:
Existing flue for unit no. 4 is enclosed in a common annulus

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): Municipal Solid Waste		
2. Source Classification Code (SCC): 50100105	3. SCC Units: Tons burned	
4. Maximum Hourly Rate: 25 tons/hr	5. Maximum Annual Rate: 219,000 tons/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: 10
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION (CONTINUED)

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

Segment Description and Rate: Segment __ of __

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**016**		**EL**
SO2	**067**		**EL**
NOx	**107**	**026**	**EL**
Pb	**016**		**EL**
HF	**067**		**EL**
Hg	**207**		**EL**
Cd	**016**		**EL**
HCl	**067**		**EL**
PCDD/PCDF	**016**		**EL**
CO	**025**		**EL**
VOC	**067**		**EL**
SAM	**067**		**EL**

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.7 lb/hour 25.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 20.6 mg/dscm @ 7% O2	4. Equivalent Allowable Emissions: 5.7 lb/hour 25.1 tons/year
5. Method of Compliance: USEPA Method 5	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 19.2 lb/hour 84.3 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 26 ppmv @ 7% O2	4. Equivalent Allowable Emissions: 19.2 lb/hour 84.3 tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 80% reduction	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 58.5 lb/hour 256.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 110 ppmv @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: Pb	2. Total Percent Efficiency of Control:
3. Potential Emissions: 5.5×10^{-2} lb/hour 0.243 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.2 mg/dscm @ 7% O2	4. Equivalent Allowable Emissions: 5.5×10^{-2} lb/hour 0.243 tons/year
5. Method of Compliance: USEAP Method 29	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

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

1. Pollutant Emitted: HF	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.80 lb/hour 3.5 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 3.5 ppmv @ 7% O2	4. Equivalent Allowable Emissions: 0.80 lb/hour 3.5 tons/year
5. Method of Compliance: USEPA Method 13 A or 13B	
6. Allowable Emissions Comment (Description of Operating Method): Proposed as initial stack test only	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Hg**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 0.037 lb/hour 0.163 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.028 mg/dscm @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 29	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 85% reduction	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 29	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **Cd**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 4.56×10^{-3} lb/hour 0.02 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code:
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.02 mg/dscm @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 29	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ___ of ___

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

Allowable Emissions Allowable Emissions ___ of ___

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **HCl**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25.36 lb/hour 111.1 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 25 ppmdv @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 26 or 26A	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 95% reduction	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 26 or 26A	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PCDD/PCDF**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 3.61 x 10^{-6} lb/hour1.58 x 10^{-5} tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 13 ng/dscm @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 23	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25.89 lb/hour 113.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 80 ppmdv @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: CEMS	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **ozone (as VOC)**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 2.74 lb/hour 12 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 0.1 lb/ton	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 18 or 25A, initial stack test only	
6. Allowable Emissions Comment (Description of Operating Method): Based on Harrisonburg, VA RRF emission limit	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SAM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 16.99 lb/hour 74.4 tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: N/A Reference:	7. Emissions Method Code: 0
8. Calculation of Emissions: See Volume III, Section 4	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: 15 ppmdv @ 7% O2	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: USEPA Method 8, initial stack test only	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

EMISSIONS UNIT INFORMATION
Section [1] of [1]

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: COMS	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation ___ of ___

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 4

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... to be determined Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60.58b(b)	

Continuous Monitoring System: Continuous Monitor 2 of 4

1. Parameter Code: EM	2. Pollutant(s): CO
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... to be determined Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60.58b(i)	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 4

1. Parameter Code: EM	2. Pollutant(s): SO2
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... to be determined Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60.58b(e)	

Continuous Monitoring System: Continuous Monitor 4 of 4

1. Parameter Code: EM	2. Pollutant(s): NOx
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... to be determined Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: 40 CFR 60.58b(h)	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: see comment ☐ Previously Submitted, Date __

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: see comment ☐ Previously Submitted, Date __

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: see comment ☐ Previously Submitted, Date __

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: _________ ☐ Previously Submitted, Date ________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: see comment ☐ Previously Submitted, Date __
☐ Not Applicable

6. Compliance Demonstration Reports/Records

☐ Attached, Document ID: ________

Test Date(s)/Pollutant(s) Tested: ______________________________

____

☐ Previously Submitted, Date: ______

Test Date(s)/Pollutant(s) Tested: ______________________________

____

☐ To be Submitted, Date (if known):________

Test Date(s)/Pollutant(s) Tested: ______________________________

____

☒ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute

☒ Attached, Document ID: see comment__ ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1] of [1]

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☒ Attached, Document ID: see comment ☐ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☒ Attached, Document ID: see comment ☐ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: see comment ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: see comment_
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: __________ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: __________ ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: __________ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:__________
      ☐ Previously Submitted, Date:________
   ☒ Not Applicable

Additional Requirements Comment

Supporting information is located throught Volume III of the Application for Pawer Plant Site Certification