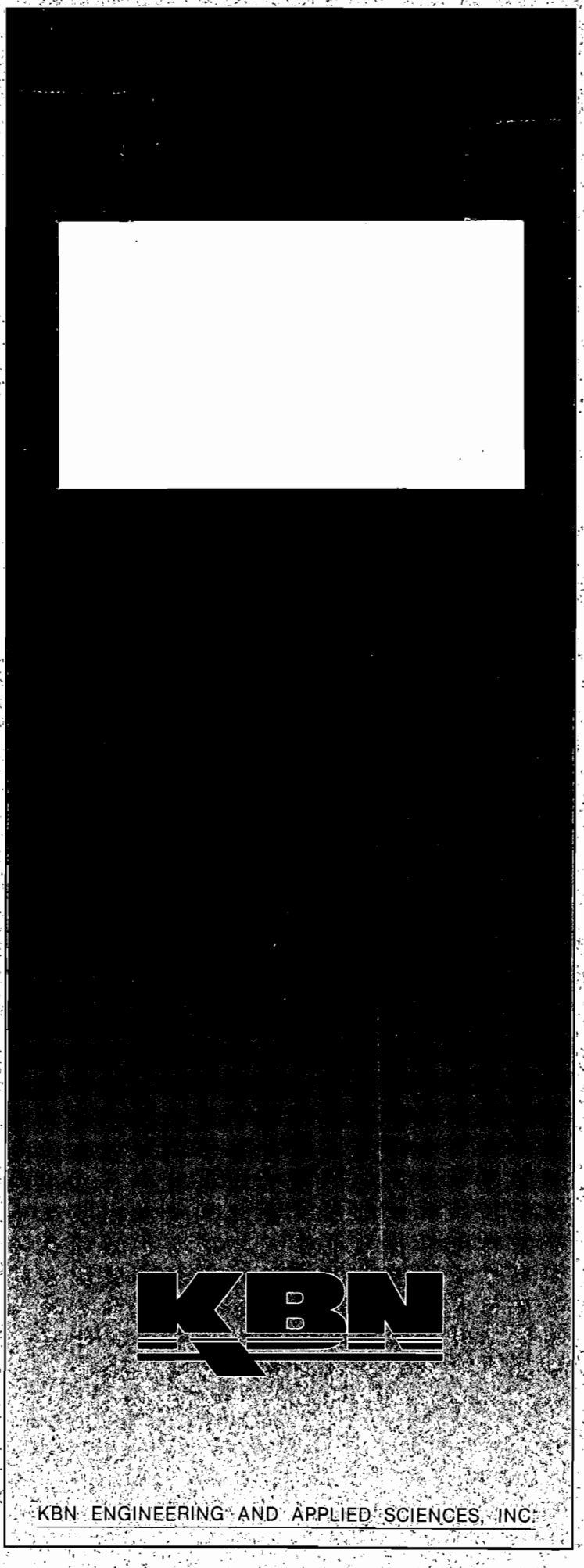
KBN
KBN ENGINEERING AND APPLIED SCIENCES, INC.

SUPPLEMENTAL AIR MODELING ANALYSIS

CONTAINER CORPORATION OF AMERICA, INC.

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TABLE OF CONTENTS

1.0 INTRODUCTION

An air quality impact evaluation of the Container Corporation of America, Inc., (CCA) paper mill, located in Fernandina Beach, Florida, was submitted to the Florida Department of Environmental Regulation (FDER) in November 1990 (KBN, 1990). The report provided an initial demonstration of compliance of the CCA facility with air quality standards.

The report contained herein presents the results of a supplemental air quality modeling analysis for the CCA paper mill. The analysis was conducted in response to a request by FDER with regard to the proposed construction of a new batch digester and brown stock washer system (permit numbers AC45-190382, AC45-190383, and PSD-FL-165). The request was transmitted to CCA in a letter from FDER dated December 18, 1990 (see Appendix A). It was requested that certain supplemental evaluations be submitted to confirm that the affected facility, after the proposed modification, will not violate prevention of significant deterioration (PSD) allowable increments and ambient air quality standards (AAQS).

Further clarification of this request was obtained from Mr. Tom Rogers of FDER in a telephone conversation on December 19, 1990. KBN confirmed this conversation and the agreements reached in a letter to Mr. Rogers dated December 21, 1990 (see Appendix B). Subsequently, Mr. Cleve Holladay of FDER verbally transmitted comments regarding the December 21 letter to Mr. David Buff of KBN. His comments are summarized below:

1. With regard to item 3 of the December 21 letter, if short-term modeling of other sources was required, sources located within 50 km of the impact area should be included if they are determined to have a significant impact upon the significant impact area.
2. A visibility impact analysis should be conducted for the Okefenokee and Wolf Island PSD Class I areas.

The remainder of this report presents the data, methodology, assumptions, and results that demonstrate that the proposed CCA project will not violate any PSD increment or AAQS.

Presented in Section 2.0 are the actual emissions increases associated with the proposed project, as documented in previous submittals to FDER. This analysis shows that the proposed project, not considering any previous contemporaneous decreases at the facility, will trigger PSD review for total suspended particulate matter [PM(TSP)], particulate matter less than 10 microns in diameter (PM10), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), beryllium (Be), and sulfuric acid mist (H_2SO_4).

The air quality impact analysis is presented in Section 3.0, including the methodology and results. The modeling analysis for PM(TSP), PM10, SO_2, and NO_x demonstrates that the air quality impacts as a result of the increase in actual emissions from the proposed facility are below the established FDER significance levels. As a result, no further modeling analysis is required for these pollutants, in accordance with PSD modeling policy, and as confirmed by FDER. The previous modeling study for CCA (KBN, 1990) demonstrated that the impact of CO emissions from the facility are insignificant, and therefore no further modeling is required for CO.

In the case of Be and H_2SO_4, the modeling analysis was performed to address conformance with FDER's toxics policy. This policy establishes an acceptable ambient concentration (AAC) for each toxic pollutant. In addition, a risk analysis was performed for Be. These analyses demonstrate that impacts of Be and H_2SO_4 caused by the CCA facility are well below the levels of concern.

A soils, vegetation, and visibility impact analysis is presented in Section 4.0. This analysis is conducted for the two PSD Class I areas: the Okefenokee National Wildlife Refuge and the Wolf Island National Wildlife Refuge.

2.0 EMISSION INCREASES AND PSD APPLICABILITY

The proposed project, consisting of a new batch digester (No. 8) and brown stock washer (C-line), will result in an increase in actual emissions from several sources at the CCA mill. These increases have been calculated on an annual average basis, as documented in a previous submittal to FDER (see Appendix C). The increase in actual annual average emissions (in tons per year) associated with each source at CCA are presented in Table 2-1. These increases are based on estimates of increased nominal input rates for the individual sources considered. The increases will serve as inputs to the annual air quality modeling analysis.

The total increase in annual emissions from all sources at CCA, as a result of the proposed project, are summarized in Table 2-2. Also shown are the PSD significant emission rates for each pollutant, as contained in Florida Administrative Code, Rule 17-2.500(2)(e). As indicated, PSD review applies for PM(TSP), PM10, SO_2, NO_x, CO, Be, and H_2SO_4. It is noted that this analysis does not include the contemporaneous reductions from the shutdown of Power Boiler No. 4 at CCA, which occurred within the past five years.

For modeling purposes, an estimate of maximum, or peak, short-term emissions from each unit is required. This discussion will show that the expected short-term emission rate, as estimated from peak input rate, will not change for any of the units under consideration after startup of the new equipment. It should be noted that CCA has not requested any increase in permitted operating rate for any currently permitted source.

For the purposes of this report, the sources considered as representing potential increases in actual emissions include the following:

Power Boiler No. 7
Power Boiler No. 5
Recovery Boiler No. 4 and SDT
Recovery Boiler No. 5 and SDT

Omitted from this analysis is Lime Kiln No. 4. As discussed in previous submittals, this source has only recently begun operation, and we lack

sufficient historical data to relate actual emissions to operating rate. Thus, all modeling assumes that actual emissions are equivalent to permitted emissions; therefore, no increase is shown from Lime Kiln No. 4 for the proposed project.

Each of the four sources considered is tied to the mill overall energy balance for both steam and power. In addition, the mill currently cogenerates and sells power to the local utility company. Other factors that determine the peak operating rate at any given time include fuel availability, current generating capability of each unit, maintenance outages throughout the mill, etc. The influence of these factors will be discussed below.

Power Boiler No. 7 is a coal-fired unit with a steaming capacity of 770,000 lb/hr. This boiler is typically fired at near full load since this is the least expensive fossil fuel used in the mill. However, there are times when this boiler has been required to fire close to the maximum amount of coal it can burn. This will also be true in the future. This means the boiler occasionally burns very nearly its permitted limit of coal on a daily basis.

Examples taken from 1990 production records include the following:

Date	Coal Burned (TPD)	Reason
1/31/90	853	PB5 down for maintenance
6/12/90	852	RB5 down for maintenance
7/30/90	848	PB5 down for maintenance
9/16 - 9/20	850 - 870	PB5 down for maintenance
11/01/90	871	RBs low on liquor
11/05/90	852	RBs low on liquor

As can be seen from the reasons for high coal usage, an outage or partial outage on any of the other steam-generating units in the mill will cause coal consumption to approach the permit limit (about 39 tons/hour or 936 tons/day). All of the figures in the above table are at least 90 percent of the permitted rate. Fuel availability in the recovery boilers (black liquor) also can limit the steam-generating capacity of these units,

causing more load to shift to the power boilers. These situations exist now, as seen above, and will exist after the project startup. Thus, the peak maximum fuel consumption of Power Boiler No. 7 will not change after the startup of the new digester and washer.

Power Boiler No. 5 is a combination oil- and bark-/woodwaste-fired unit with a nominal steaming capacity of 500,000 lb/hr. Since fuel oil is the most expensive fossil fuel used in the mill, its use is normally minimized. Thus, this unit normally is base-loaded with as much bark as is practical, and oil is used only to make up for short-term shortages in steam generation in the other generating equipment. This occurs occasionally at present, as shown in the following table of examples from 1990 production data:

Date	Oil Usage (GPD)	Reason
2/08 - 2/10/90	48,804 to 61,656	PB7 down for maintenance
6/11 - 6/12/90	50,694 to 59,976	PB5 down for maintenance
7/09 - 7/10/90	42,126 to 55,902	RB4 down for maintenance
10/13/90	58,716	RB5 down for maintenance

During these periods of significant firing of oil in addition to bark, Power Boiler No. 5 is operating at close to its maximum steaming capacity. These conditions will continue after startup of the proposed project. Thus, the peak input rate for Power Boiler No. 5 is not expected to be different after startup of the project.

Both recovery boilers and smelt dissolving tanks rely on black liquor solids as process input. The black liquor solids derived from the pulping operation are supplemented independently with outside liquor (either swapped or purchased). The nature of the process also generally requires more maintenance on recovery boilers than power boilers. For these reasons, the boilers frequently operate at or near their permitted maximum input rates (284,280 lb/hr BLS combined), as shown in the following table:

Date	BLS Burned (lb/hr combined)
1/10/90	271,750
1/11/90	274,333
2/17/90	276,583
2/18/90	277,417
6/24/90	277,250
8/31/90	283,667
9/01/90	261,833

Since these boilers are shown to operate at times currently at or near their operating limits, and we have not requested an increase in operating limits, the peak input rates for the recovery boilers and SDTs will not increase after startup of the proposed units.

Table 2-1. Summary of Calculated Net Emission Increase Per Rule 17-2.500(2)(e)

Regulated Pollutant	Increase in Emissions (TPY)						TOTALS
	PB 5	PB 7	RB 4	RB 5	SDT 4	SDT 5	
Particulate (TSP)	4.8	5.3	20.6	7.2	4.8	1.9	44.6
Particulate (PM10)	3.0	3.5	15.5	5.4	4.3	1.7	33.4
Sulfur dioxide	67.1	263.6	53.0	64.7	1.3	1.5	451.2
Nitrogen oxides	11.5	143.8	24.6	30.1	--	--	210.0
Carbon monoxide	0.9	22.0	132.1	161.5	--	--	316.5
Volatile organic compounds	0.13	0.7	10.5	12.8	--	--	24.1
Lead	0.00022	0.0063	0.013	0.010	--	--	0.03
Mercury	0.00006	0.0019	--	--	--	--	0.002
Beryllium	0.000015	0.00072	0.00100	0.00077	--	--	0.0025
Arsenic	0.00006	0.01	0.0035	0.0026	--	--	0.016
Fluorides	0.00016	2.23	--	--	--	--	2.23
Sulfuric acid mist	3.1	12.1	0.69	0.53	--	--	16.42
Total reduced sulfur	--	--	0.36	0.40	0.51	0.03	2.01[a]
Asbestos	--	--	--	--	--	--	0.0
Vinyl Chloride	--	--	--	--	--	--	0.0

[a]Includes 0.71 TPY TRS from proposed brown stock washer.

Table 2-2. Summary of Calculated Net Emissions Increases[a]

Regulated Pollutant	Net Emissions Increase[b]	Significant Emission Rates from Table 500-2[a] (TPY)
Particulate (TSP)	44.6	25
Particulate (PM10)	33.4	15
Sulfur dioxide	451.2	40
Nitrogen oxides	210.0	40
Carbon monoxide	316.5	100
Volatile organic compounds	24.1	40
Lead	0.03	0.6
Mercury	0.002	0.1
Beryllium	0.0025	0.0004
Fluorides	2.23	3
Sulfuric acid mist	16.42	7
Total reduced sulfur	2.01	10
Asbestos	0.0	0.007
Vinyl Chloride	0.0	1

[a]Per Florida Administrative Code, Rule 17-2.500.
[b]Does not consider any other contemporaneous decreases at CCA.

3.0 AIR QUALITY IMPACT ANALYSIS

3.1 MODELING METHODOLOGY

3.1.1 Applicability

Modeling was performed for each pollutant for which there will be a significant increase in emissions as a result of the proposed modification at CCA. These pollutants include the criteria pollutants NO_x, SO_2, PM(TSP), and PM10, and the non-criteria pollutants Be and H_2SO_4. As stated previously, CO modeling conducted previously has shown CO impacts to be insignificant. Pollutant increases are predicted for Power Boilers 5 and 7, Recovery Boilers 4 and 5, and Smelt Dissolving Tanks 4 and 5. All proposed emission increases will be for the annual averaging period only. Short-term maximum emissions for the above sources will not change as a result of the proposed modification.

3.1.2 Significant Impact Analysis

It was first determined whether the proposed annual increase in emissions for each criteria pollutant would cause an increase in ambient concentration levels in the vicinity of the CCA plant that are in excess of the significant impact levels for these pollutants. For this analysis, dispersion modeling was performed using the ISCST model. The methodology is consistent with the methodology presented in previous dispersion modeling analysis for the CCA mill (KBN, 1990).

The increase in annual PM(TSP), SO_2, and NO_x emissions resulting from the proposed change at CCA are summarized in Table 3-1. These figures are obtained from Table 2-1 and are based on the report in Appendix C.

For modeling purposes, it was assumed that PM10 emissions are equal to PM(TSP) emissions, which is conservative since PM10 emissions actually are lower than PM(TSP) emissions. Stack parameters and building downwash data for the CCA sources were obtained from the 1990 KBN report. The modeling analysis also incorporates CCA's proposed change to Power Boiler No. 5, which is being modified as part of the proposed batch digester and brown stock washer additions. CCA is proposing to raise the height of the power

boiler stack from 227 feet (ft) to 257 ft. This will alleviate a downwash problem with the power boiler and result in lower ground level impacts from this source.

For toxic pollutants, maximum impacts were determined for the total CCA plant emission rates for those pollutants (i.e., the existing emission rate plus the increases as a result of the proposed modification). These emission rates are presented in Table 3-2. Supporting documentation is contained in Appendix C. A risk assessment also was performed based on the maximum annual Be concentration.

Concentrations for criteria pollutants were determined for the annual average time period. Maximum refined concentrations were compared to the respective annual average significant impact concentrations. For H_2SO_4, 8-hour and 24-hour concentrations were determined. For Be, 8-hour, 24-hour, and annual average concentrations were produced. Maximum concentrations were compared to the respective 8-hour and 24-hour acceptable ambient concentrations (AAC).

Both screening and refined receptors were used in the modeling analysis to determine pollutant maximum impacts. The screening receptors included both discrete and polar grid receptors. The discrete receptors consisted of 36 inner receptors outlining CCA's property boundary at every 10-degree radial direction, plus 46 additional receptors beyond plant property at distances of 400m and 700m in all applicable directions. In addition to the 86 total discrete receptors, a receptor grid was used that consisted of eight distances (1,000; 1,300; 1,700; 2,100; 2,500; 3,000; 4,000; and 5,000 meters) and 36 directions in 10-degree increments from the CCA plant.

A refined receptor grid was used to determine the maximum pollutant impacts. For criteria pollutants, the grid generally was centered on the location of the maximum annual concentration from the screening analysis. Refined receptor grids consisted of receptors at every 100-m distance interval and at directional intervals of 2 degrees between adjacent

interval and at directional intervals of 2 degrees between adjacent screening receptors. For maximum screening impacts that occurred on plant property closer than 800m of the origin, directions were refined to 5-degree intervals out to 700m and then at 2-degree intervals for distances of 800m and 900m. For toxic pollutants, similar polar refinement receptor grids were centered on locations of the highest 8-hour and 24-hour screening modeling impacts. All impacts were based on a 5-year meteorological record (1983-1987) from Jacksonville.

3.1.3 PSD Class I Analysis For SO_2

Modeling was performed to determine the total SO_2 PSD increment consumption at the two PSD Class I areas located within 100 km of the CCA plant. The analysis included all of CCA's and Gilman Paper's baseline and future emission sources (refer to KBN 1990 report), along with all major Duval and Nassau County increment-consuming sources, including the JEA St. John's River Power Park Units 1 and 2, the AES project at Cedar Bay (with Seminole Kraft), ES-Metals, the U.S. Naval Station at Cecil Field, Duval Asphalt, Anheiser Busch, and SCM Corp. This inventory was derived from a previous KBN report (KBN, 1987). There have been no known changes in the inventory since 1987. The ITT Rayonier paper mill is not included in the increment consumption inventory since there have been no PSD-affecting changes at the mill since the baseline date.

Eleven receptors were modeled along the eastern border of the Okefenokee Wildlife Refuge. One receptor was located along the southern boundary of the Wolf Island Class I area, located to the north of CCA. In order to produce maximum impacts, these receptors were located along the borders of the Class I area closest to CCA and Duval County sources.

Emission, stack, and building parameters for the AES sources were obtained from the AES Cedar Bay Site Certification Application (revised) (Black and Veatch, 1990). Stack and building parameters for the Seminole Kraft and JEA St. John's River sources were obtained from previous dispersion modeling studies submitted to FDER (KBN, 1987; KBN, 1989). A half-life

decay factor of 4 hours for SO_2 was used to be consistent with these prior modeling studies.

3.2 RESULTS

3.2.1 Criteria Pollutants

Screening modeling results for the significant impact analyses for SO_2, NO_x, and PM(TSP) are presented in Table 3-3. PM(TSP) emissions were used for the PM10 results as well since PM(TSP) emissions are greater than PM10 emissions, and the significant impact level is the same for both.

The maximum predicted increase in annual average SO_2 concentrations, as a result of the proposed modification only, is 0.24 $\mu g/m^3$, which is below the PSD significant impact level of 1 $\mu g/m^3$. The maximum predicted increase in annual PM(TSP)/PM10 and NO_x concentrations are 0.06 and 0.14 $\mu g/m^3$, respectively, which also are well below their significance levels of 1 $\mu g/m^3$.

Refined modeling results for SO_2, NO_x, and PM(TSP)/PM10 indicated no change in concentration magnitude and location from the screening model results. The results indicate that CCA's proposed emission increases for criteria pollutants will not exceed PSD significant impact levels for those pollutants. Therefore, as agreed upon by FDER, a full modeling analysis, including other interacting sources, was not performed.

3.2.2 Toxic Pollutants

Screening modeling results for the significant impact analyses for H_2SO_4 and Be are presented in Table 3-4. The maximum predicted 8-hour and 24-hour sulfuric acid mist concentrations are 3.06 and 1.72 $\mu g/m^3$, respectively, which are below the 8-hour and 24-hour AAC of 10 and 2.38 $\mu g/m^3$. The maximum predicted 8-hour and 24-hour beryllium concentrations are 0.00079 and 0.00045 $\mu g/m^3$, respectively, which are below the 8-hour and 24-hour AAC of 0.02 and 0.0048 $\mu g/m^3$. Refined modeling results for these two pollutants indicated no change in concentration magnitude and location from the screening model results.

3.2.3 PSD Class I Analysis

The modeling results for the SO_2 PSD Class I analysis are presented in Table 3-5. The results indicate that the PSD Class I increment is not exceeded based on emissions from all increment-consuming and -expanding sources. The maximum annual, 3-hour, and 24-hour increment consumption concentrations from all sources is 0.08, 13.2, and 3.43 $\mu g/m^3$, respectively.

Based on Table 2-1

Table 3-1. Increase in Annual Average Emissions at CCA Due to Proposed Project

Source	SO_2 (TPY)	SO_2 (g/s)	PM (TSP) (TPY)	PM (TSP) (g/sec)	NO_x (TPY)	NO_x (g/sec)
Power Boiler 5[a] (baseline)	675.1 67.1	19.42	47.1 4.8	1.35	602.4 11.5	17.33
Power Boiler 5 (future)	742.2	21.35	51.9	1.49	613.9	17.66
Power Boiler 7	263.6	7.58	5.3	0.15	143.8	4.14
Recovery Boiler 4	53.0	1.52	20.6	0.59	24.6	0.71
Recovery Boiler 5	64.7	1.86	7.2	0.21	30.1	0.87
Smelt Dissolving Tank 4	1.3	0.04	4.8	0.14	----	----
Smelt Dissolving Tank 5	1.5	0.04	1.9	0.05	----	----

[a]Stack height will increase from 227 ft to 257 ft.

(g/s) emissions based on 8760 hours/yr

Table 3-2. Future Be and H_2SO_4 Emissions For CCA Sources

Source	Beryllium				H_2SO_4 Mist			
	Current Actual (TPY)	Increase[a] (TPY)	Total (TPY)	Total (g/s)	Current Actual (TPY)	Increase[a] (TPY)	Total (TPY)	Total (g/sec)
Power Boiler 5	0.0035	0.000015	0.003515	0.00010	31.0	3.1	34.1	0.981
Power Boiler 7	0.0090	0.00072	0.00972	0.00028	151.3	12.1	163.4	4.70
Recovery Boiler 4	0.013	0.001	0.014	0.00043	8.91	0.69	9.6	0.276
Recovery Boiler 5	0.010	0.00077	0.011	0.00032	1.72	0.53	2.25	0.065

[a]Due to proposed project.

Table 3-3. Maximum Predicted Increase in Annual Average Concentrations For Criteria Pollutants

Pollutant	Year	Concentration ($\mu g/m^3$)	Receptor Location: Direction (°)	Receptor Location: Distance (m)	Significant Impact Level ($\mu g/m^3$)
Sulfur Dioxide					
	1983	0.24[a]	80	693	1
	1984	0.18	80	693	
	1985	0.23	80	693	
	1986	0.18	80	693	
	1987	0.21	80	693	
Nitrogen Oxides					
	1983	0.14[a]	80	693	1
	1984	0.10	80	693	
	1985	0.13	80	693	
	1986	0.08	80	693	
	1987	0.12	80	693	
Particulate Matter (TSP)					
	1983	0.05	280	400	1
	1984	0.04	80	693	
	1985	0.05	80	693	
	1986	0.06[a]	60	610	
	1987	0.05	80	693	

[a]Refined concentrations.

Table 3-4. Maximum Predicted Concentrations For Toxic Pollutants With Respect to Acceptable Ambient Concentrations

Pollutant/ Aver.Time	Year	Concentration ($\mu g/m^3$)	Receptor Location Direction (°)	Receptor Location Distance (m)	Acceptable Ambient Concentration ($\mu g/m^3$)
Beryllium					
8-Hour	1983	0.00077	290	347	0.02
	1984	0.00060	240	514	
.00087	1985	0.00079[a]	290	347	
	1986	0.00067	60	610	
	1987	0.00079[a]	60	610	
24-Hour	1983	0.00045[a]	280	400	0.0048
	1984	0.00033	50	457	
	1985	0.00036	60	610	
	1986	0.00042	60	610	
	1987	0.00033	260	526	
Sulfuric Acid Mist					
8-Hour	1983	2.73	230	472	10
	1984	2.45	230	472	
	1985	3.06[a]	230	472	
	1986	2.28	230	472	
	1987	2.94[a]	230	472	
24-Hour	1983	1.72[a]	220	450	2.38
	1984	1.37	30	511	
	1985	1.66[a]	230	472	
	1986	1.16	230	472	
	1987	1.45	230	472	

[a]Refined concentrations.

Table 3-5. Maximum Predicted SO_2 PSD Increment Consumption in the Class I Areas

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location Direction (°)	Receptor Location Distance (m)	Allowable PSD Increment ($\mu g/m^3$)
Annual					
	1983	0.08	261	67000	2
	1984	0.07	283	68100	
	1985	0.07	267	64316	
	1986	0.05	261	74200	
	1987	0.07	261	74200	
3-Hour[a]					
	1983	12.9	261	67000	25
	1984	12.0	266	65300	
	1985	13.2	267	64316	
	1986	11.9	271	66200	
	1987	11.2	261	74200	
24-Hour[a]					
	1983	3.43	267	64316	5
	1984	3.04	267	64316	
	1985	3.06	271	66200	
	1986	3.05	275	63699	
	1987	3.36	275	63699	

[a]Highest, second-highest concentrations presented.

4.0 ADDITIONAL IMPACT ANALYSIS

4.1 IMPACTS ON SOILS AND VEGETATION

As described in the air quality impact analysis, the maximum increase in concentrations in the vicinity of CCA as a result of the proposed project are predicted to be below significance levels for all pollutants. As a result, no detrimental effects on soils or vegetation should occur in this area.

The analysis also demonstrated that PSD increment consumption in the Okefenokee and Wolf Island Class I areas will be well below the Class I increments for SO_2. The maximum increment consumption is 70 percent of the allowable increment (predicted for the 24-hour SO_2 increment), but CCA does not contribute to this value. Annual increment consumption in the Class I area is well below the PSD increment. As a result, no significant effect on soils or vegetation should occur.

4.2 IMPACTS ON VISIBILITY

The visibility analysis required by PSD regulations is directed primarily toward Class I areas. The Clean Air Act Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration caused by various pollutants. The nearest Class I area to the proposed facility is the Okefenokee National Wildlife Refuge, located about 64 km from the facility.

A level-1 visibility screening analysis was performed to determine the potential adverse visibility effects using the approach suggested in the Workbook for Plume Visual Impact Screening and Analysis (EPA, 1988). The Level-1 screening analysis is designed to provide a conservative estimate of plume visual impacts (i.e., impacts higher than expected). The EPA model, VISCREEN, was used for this analysis. Model input and output results are presented in Table 4-1. The projected increase in emissions caused by the proposed project, as presented in Table 2-2, was used as

input to the model. As indicated, the maximum visibility impacts caused by the proposed increase do not exceed the screening criteria inside or outside the Class I area. As a result, there is no significant impact upon visibility predicted for the Class I areas.

4.3 IMPACTS DUE TO ASSOCIATED POPULATION GROWTH

There will be a small increase in the number of temporary construction workers during construction. There will be a minimal increase in permanent employment at CCA as a result of adding the new batch digester and brown stock washer. As a result, there will be no permanent impacts on air quality caused by associated population growth.

Table 4-1. Results for Visual Effects Screening Analysis

Visual Effects Screening Analysis for
Source: CONTAINER CORP OF AMERIC
Class I Area: OKEFENOKEE N.W.R.

*** Level-1 Screening ***

Input Emissions for

Particulates	44.60	TON/YR
NOx (as NO2)	210.00	TON/YR
Primary NO2	.00	TON/YR
Soot	.00	TON/YR
Primary SO4	16.42	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	64.00 km
Min. Source-Class I Distance:	64.00 km
Max. Source-Class I Distance:	90.00 km
Plume-Source-Observer Angle:	11.25 degrees

Stability: 6
Wind Speed: 1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	64.0	84.	2.00	.072	.05	.000
SKY	140.	84.	64.0	84.	2.00	.024	.05	-.001
TERRAIN	10.	84.	64.0	84.	2.00	.022	.05	.000
TERRAIN	140.	84.	64.0	84.	2.00	.006	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	65.	59.7	104.	2.00	.076	.05	.000
SKY	140.	65.	59.7	104.	2.00	.025	.05	-.001
TERRAIN	10.	55.	57.3	114.	2.00	.029	.05	.000
TERRAIN	140.	55.	57.3	114.	2.00	.008	.05	.000

REFERENCES

Black and Veatch. 1990. AES Cedar Bay Site Certification Application (Revised).

KBN Engineering and Applied Sciences, Inc. (KBN). 1987. Air Construction Permit Application for SO_2 Emission Increase; Power Boiler No. 10, Jefferson Smurfit Corporation, Jacksonville, Florida. Gainesville, Florida.

KBN Engineering and Applied Sciences, Inc. (KBN). 1989. PSD Permit Application--New Recovery Boiler, Evaporators, and Smelt Dissolving Tank. Seminole Kraft Corporation. Gainesville, Florida.

KBN Engineering and Applied Sciences, Inc. (KBN). 1990. Air Quality Impact Analysis: Container Corporation of America, Inc. Gainesville, Florida.

U.S. Environmental Protection Agency (EPA). 1988. Workbook for Plume Visual Impact Screening and Analysis. EPA Report No. EPA-450/4-88-015.

APPENDIX A

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Bob Martinez, Governor Dale Twachtmann, Secretary John Shearer, Assistant Secretary

December 18, 1990

RECEIVED
DEC 18 1990
OERTEL, HOFFMAN, FERNANDEZ & COLE, P.A.

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Wayne Barlow, General Manager
Container Corporation of America
North 8th Street
Fernandina Beach, Florida 32034

Dear Mr. Barlow:

Re: PSD Applicability Associated with the Proposed Facility Modification

The Department has reviewed the response prepared by KBN Engineering and Applied Sciences, Inc., and received on December 6, 1990 (P.E. sealed copy received on December 17, 1990). Based on discussions with U.S. EPA, Region IV, contemporaneous emissions credit cannot be granted for the No. 4 Power Boiler. Consequently, PSD evaluation for increment and air quality standards is required for all of the pollutants equal to or greater than the applicable significant emission rates listed in Table 500-2, F.A.C. Chapter 17-2. Therefore, please submit the following information to the Department's Bureau of Air Regulation (BAR), including all calculations, assumptions and reference material:

1. The appropriate evaluations that will demonstrate that the affected facility, after the proposed modification, will not violate increment and standards (see attached EPA letter). This should be coordinated with Mssrs. Tom Rogers and Cleve Holladay. They can both be reached at 904-488-1344. Also, this data should be submitted to the BAR no later than January 10, 1991.

2. Referring to #1 above, the evaluations should include the confirmation of all stack parameters (i.e., height, diameter, exit velocity, etc.) and building parameters (i.e., height, width, etc.) at all facilities used in the evaluations.

3. The appropriate fee for this evaluation (PSD) is $5,000.

If there are any questions, please call Bruce Mitchell at 904-488-1344 or write to me at the above address.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BM/plm

Attachments

c: A. Kutyna, NED
G. Smallridge, OGC
T. Cole, OHF&C

APPENDIX B

December 21, 1990

Mr. Tom Rogers
Bureau of Air Monitoring and Assessment
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Container Corporation of America
Proposed Batch Digester and Brown Stock Washer

Dear Mr. Rogers:

This letter is to confirm the agreements reached in our recent telephone conversation related to further modeling analysis for the above-referenced permit applications. The further modeling is necessary based on the Florida Department of Environmental Regulation's (FDER's) position that PSD is triggered for several pollutants as a result of the proposed project. The net increases in emissions were presented in KBN's report submitted to FDER on December 17, 1990. These emission increases were accepted by FDER; however, the reductions from the shutdown of Power Boiler No. 4 were determined not to be creditable. Based solely on the increases in emissions as a result of the proposed batch digester and brown stock washer, PSD is triggered for the following pollutants: total suspended particulate matter [PM(TSP)], particulate matter less than 10 μm diameter (PM10), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), beryllium (Be), and sulfuric acid mist (H_2SO_4). These pollutants, therefore, require a PSD modeling analysis.

The agreements concerning the modeling analysis necessary to satisfy PSD requirements are summarized below:

1. For the criteria pollutants, which have defined significant impact levels, only the increase in actual emissions caused by the proposed modification will be modeled initially (annual average emission changes documented in the December 17 submittal; short-term averaging time changes to be documented by CCA/KBN). The modeling also will consider the proposed increase in stack height on Power Boiler No. 5.

2. For those criteria pollutants for which the increase in actual emissions results in an insignificant impact, as determined in item 1 above, no further modeling will be required except for the PSD Class I areas (see item 4 below).

3. For those criteria pollutants for which the increase in actual emissions results in a significant impact, as determined in item 1 above, further modeling will be required. The modeling would be essentially the same as the previous modeling submitted by KBN (i.e., address compliance with ambient air quality standards and PSD

increments); however, the significant impact area (SIA) for the CCA mill would be defined, and all major sources within the SIA would be modeled to determine total air quality impacts. Also, those sources located within 50 km of the SIA will be considered in the annual average modeling analysis (per PSD Workshop Manual). The North Carolina screening method will be used to screen potential sources.

4. SO_2 impacts upon the PSD Class I areas will be updated to include other increment-consuming sources within the SIA. As a minimum, the St. Johns River Power Park and Cedar Bay cogeneration projects will be included. The previous modeling has demonstrated that the PM and NO_2 impacts upon the Class I areas are negative or close to zero, and that further modeling of these pollutants in the Class I area is not necessary.

5. The impacts of Be and H_2SO_4 emissions will be evaluated in relation to FDER's toxics policy, which defines acceptable ambient concentration (AAC) levels for each toxic pollutant. CCA's total impacts for these two pollutants will be evaluated and compared to the AAC's.

By copy of this letter, CCA is requesting that Steve Smallwood and his permitting staff also review this agreement. If FDER has any comments as to whether the additional information, as outlined above, will be sufficient to conclude the evaluation of this proposed project, please relate them to me by January 3, 1991.

KBN is planning to submit the required analysis to CCA before the January 10, 1991, deadline. Thank you for your cooperation in this matter.

David A. Buff

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

DAB/dmw

cc: Roger Hagan
Terry Cole
Bob Williams

90017A2/1

APPENDIX C

NET EMISSIONS INCREASE ANALYSIS

FOR

CONTAINER CORPORATION OF AMERICA, INC.

Prepared For:

Container Corporation of America, Inc.
Fernandina Beach, Florida

Prepared By:

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

David A. Buff, P.E.

Florida P.E. #19011

December 1990
90017A2

INTRODUCTION

This report was prepared by KBN for the purpose of determining whether the addition of the No. 8 Batch Digester and C-Line Brown Stock Washer to the CCA Fernandina Mill will require a PSD review prior to the issuance of air construction permits for these two emission sources.

The determination of whether PSD review is necessary was based on a conservative calculation of two factors as required under the Florida Administrative Code:

1. A determination was made of the actual emissions representative for the facility's operations in accordance with Rule 17-2.100(3) F.A.C.; and
2. A determination was made of the actual emission increases at the facility from the addition of the digester and washer. The facility was evaluated to determine if there will be any contemporaneous and creditable emission changes in conjunction with the addition of these two air sources.

Included in this Report is the following information:

1. Summary table of the calculations showing the projected total net emission increase or decrease from each affected source for each pollutant;
2. Summary table of the net emission increase for each pollutant as compared to the regulatory Significant Emission Rates found in Table 500-2, F.A.C.;
3. Calculations of the current actual emissions for each source, based on an average of emissions over a representative two-year period;
4. Calculations of the estimated emissions increase for each source resulting from the construction of the digester and washer; and
5. Calculation of the creditable emission reductions from Power Boiler No. 4.

The result of this analysis demonstrates that there will be no significant net emissions increase from the addition of the digester and washer at this facility. The analysis rigorously followed the procedures set forth in Rule 17-2.500(2)(e), F.A.C. Based on this analysis, PSD review is not required.

CCA Fernandina Mill--Proposed Batch Digester/Washer
Summary of Calculated Net Emissions Increases[a]

Regulated Pollutant	Net Emissions Increase	Significant Emission Rates from Table 500-2[a] (TPY)
Particulate (TSP)	-190.8	25
Particulate (PM10)	-152.6	15
Sulfur dioxide	29.4	40
Nitrogen oxides	14.1	40
Carbon monoxide	-305.5	100
Volatile organic compounds	-31.8	40
Lead	-0.03	0.6
Mercury	0.0014	0.1
Beryllium	0.0008	0.0004
Fluorides	2.23	3
Sulfuric acid mist	-3.0	7
Total reduced sulfur	2.01	10
Asbestos	0.0	0.007
Vinyl Chloride	0.0	1

[a]Florida Administrative Code, Rule 17-2.500.

CCA Fernandina Mill--Proposed Batch Digester/Washer
Summary of Calculated Net Emission Increase Per Rule 17-2.500(2)(e)

Regulated Pollutant	Changes in Emissions (TPY)							
	PB 4	PB 5	PB 7	RB 4	RB 5	SDT 4	SDT 5	TOTALS
Particulate (TSP)	-235.4	4.8	5.3	20.6	7.2	4.8	1.9	-190.8
Particulate (PM10)	-186.0	3.0	3.5	15.5	5.4	4.3	1.7	-152.6
Sulfur dioxide	-421.8	67.1	263.6	53.0	64.7	1.3	1.5	29.4
Nitrogen oxides	-195.9	11.5	143.8	24.6	30.1	--	--	14.1
Carbon monoxide	-622.0	0.9	22.0	132.1	161.5	--	--	-305.5
Volatile organic compounds	-55.9	0.13	0.7	10.5	12.8	--	--	-31.8
Lead	-0.06	0.00022	0.0063	0.013	0.010	--	--	-0.03
Mercury	-0.0006	0.00006	0.0019	--	--	--	--	0.0014
Beryllium	-0.0017	0.000015	0.00072	0.00100	0.00077	--	--	0.0008
Arsenic	-0.016	0.00006	0.01	0.0035	0.0026	--	--	0.000
Fluorides	-0.00117	0.00016	2.23	--	--	--	--	2.23
Sulfuric acid mist	-19.4	3.1	12.1	0.69	0.53	--	--	-3.0
Total reduced sulfur	--	--	--	0.36	0.40	0.51	0.03	2.01[a]
Asbestos	--	--	--	--	--	--	--	0.0
Vinyl Chloride	--	--	--	--	--	--	--	0.0

[a]Includes 0.71 TPY TRS from proposed brown stock washer.

CURRENT ACTUAL EMISSIONS

Current actual emission calculations are based on actual mill operating data over the past 2 years (1988 and 1989). Emission sources operating during this period were consistently well within permitted emission limits. These sources include:

1. Power Boiler No. 5,
2. Power Boiler No. 7,
3. Recovery Boiler No. 4,
4. Recovery Boiler No. 5,
5. Smelt Dissolving Tank No. 4,
6. Smelt Dissolving Tank No. 5, and
7. Lime Kiln No. 4 (Startup date: December 1989).

I. Power Boiler No. 5

A. Particulate Matter (TSP)

Based on annual emissions for particulate matter as reported in the Annual Operating Reports, which were based on stack test data and operating hours.

1988--31.1 TPY
1989--63.0 TPY
Average: 47.1 TPY

B. PM10

No. 5 Power Boiler is controlled with an ESP. AP-42 does not contain particle size information for bark-fired boiler equipped with an ESP. Therefore, use AP-42 factor for coal-fired boiler with an ESP: 67% of PM is PM10.

47.1 TPY x 0.67 = 31.6 TPY

C. Sulfur Dioxide

1. Fuel Oil Burning

Usages of No. 6 fuel oil in No. 5 Power Boiler were 3.527 x 10^6 gal in 1988 and 2.999 x 10^6 gal in 1989. Fuel analyses for both years showed that actual sulfur content in fuel oil was 2.5%. Using AP-42 emission factor of 157 S pounds per 1,000 gal of fuel for utility boiler where S is the percent of sulfur content in fuel oil:

SO_2 emission factor = 157S lb/10^3 gal; S = 2.5%

No. 6 oil burning in No. 5 Power Boiler:

1988 -- 3.527x10^6 gal
1989 -- 2.999x10^6 gal
Average -- 3.263x10^6 gal

SO_2 = 3.263x10^6 gal x 157(2.5)/10^3 gal/2,000 = 640.4 TPY

2. Bark Burning

Bark burning in No. 5 Power Boiler:

1988 -- 357,000 TPY
1989 -- 347,495 TPY
Average -- 352,248 TPY

AP-42 emission factor for bark burning is 0.4 lb/ton dry bark

Wet bark is 50% moisture.
Dry Bark = 352,248 x 0.5 = 176,124 TPY
SO_2 = 176,124 TPY x 0.4 lb/ton / 2,000 = 35.2 TPY

3. Total

Total average SO_2 annual emission is sum of SO_2 due to oil and bark burning:
640.4 TPY + 35.2 TPY = 675.6 TPY

D. Nitrogen Oxides

1. Fuel Oil Burning

AP-42: 67 lb/10^3 gal
3.263×10^6 gal x 67/10^3 / 2,000 = 109.3 TPY

2. Bark Burning

From AP-42: 2.8 lb/ton bark
352,248 TPY x 2.8 lb/ton / 2,000 = 493.1 TPY

3. Total

109.3 + 493.1 = 602.4 TPY

E. Carbon Monoxide

1. Fuel Oil Burning

AP-42: 5 lb/10^3 gal
3.263×10^6 gal x 5/10^3 / 2,000 = 8.2 TPY

2. Bark Burning

From NCASI Technical Bulletin No. 109, September 1980, four wood-waste boilers were tested continuously for CO emissions. Boilers B and D operated at about 300,000 lb/hr steam, which is similar to Power Boiler No. 5 operation. The 1-hour CO tests ranged from 0.042 to 0.604 lb/10^6 Btu and averaged 0.27 lb/10^6 Btu. This average value was used as the emission factor to calculate actual CO emissions:
352,248 TPY bark x 2,000 lb/ton x 4,250 Btu/lb
= 2.994×10^{12} Btu/yr
2.994×10^{12} Btu/yr x 0.27 lb/10^6 Btu / 2,000
= 404.2 TPY

3. Total

8.2 + 404.2 = 412.4 TPY

F. Volatile Organic Compounds (non-methane)

1. Fuel Oil Burning

AP-42: 0.76 lb/10^3 gal

3.263×10^6 gal x 0.76 lb/10^3 gal / 2,000 = 1.2 TPY

2. Bark Burning

AP-42: 1.4 lb/ton bark

352,248 TPY x 1.4 lb/ton / 2,000 = 246.6 TPY

3. Total

1.2 + 246.6 = 247.8 TPY

G. Trace Elements (Lead, Mercury, Beryllium, Arsenic, Fluorides)

1. Fuel Oil Burning

From "Toxic Air Polluted Emission Factors--A Compilation for Selected Air Toxic Compounds and Sources," EPA-450/2-88-006.

a. Lead

Factor is 8.9 lb/10^{12} Btu (uncontrolled)

Fuel usage = 3.263×10^6 gal

Heating value = 145,000 Btu/gal

Heat input = 3.263×10^6 x 145,000

= 0.473×10^{12} Btu/yr

Pb = 0.473×10^{12} Btu/yr x 8.9 lb/10^{12} Btu / 2,000

= 0.0021 TPY

b. Mercury

Factor is 2.4 lb/10^{12} Btu (controlled by ESP)

Hg = 0.473×10^{12} x 2.4/10^{12} / 2,000 = 0.00057 TPY

c. Beryllium

Factor is 0.59 lb/10^{12} Btu (controlled by ESP)

Be = 0.473×10^{12} x 0.59/10^{12} / 2,000 = 0.00014 TPY

d. Arsenic

Factor is 2.28 lb/10^{12} Btu (controlled by ESP)

As = 0.473×10^{12} x 2.28/10^{12} / 2,000 = 0.00054 TPY

e. Fluorides

From "Emissions Assessment of Conventional Stationary Combustion Systems, Vol V: Industrial Combustion Sources," EPA-600/7-81-003a.

Factor is 2.7 pg/J = 6.27 lb/10^{12} Btu (uncontrolled)

F = 0.473×10^{12} x 6.27/10^{12} / 2,000 = 0.0015 TPY

2. Bark Burning

All factors based on EPA-600/7-81-003a, for a controlled wood-fired stoker boiler.

a. Lead

Factor is 50 pg/J = 116 lb/10^{12} Btu

2.994×10^{12} Btu/yr x 116 lb/10^{12} Btu / 2,000 = 0.174 TPY

b. Mercury
Not measured--no emission factor available.

c. Beryllium
Factor is <1 pg/J, or <2.3 lb/10^{12} Btu
2.994x10^{12} Btu/yr x 2.3 lb/10^{12} Btu / 2,000
= 0.0034 TPY

d. Arsenic
Factor is 12 pg/J = 27.9 lb/10^{12} Btu
2.994x10^{12} Btu/yr x 27.9 lb/10^{12} Btu / 2,000
= 0.042 TPY

e. Fluorides
Not measured--no emission factor available.

3. Totals

a.	Lead:	0.0021 + 0.174	= 0.176 TPY
b.	Mercury:	0.00057 + 0	= 0.00057 TPY
c.	Beryllium:	0.00014 + 0.0034	= 0.0035 TPY
d.	Arsenic:	0.00054 + 0.042	= 0.042 TPY
e.	Fluorides:	0.0015 + 0	= 0.0015 TPY

H. Sulfuric Acid Mist
Sulfuric acid mist is estimated as 3% of sulfur emissions
SO_2 = 675.6 TPY
Sulfur = 675.6x32/64 = 337.8 TPY
Sulfuric acid mist = 337.8 x 98/32 x 0.03 = 31.0 TPY

II. Power Boiler No. 7

A. PM (TSP)
From Annual Emissions Reports, based on actual stack test and operating hours:
1988 -- 40.38 TPY
1989 -- 91.36 TPY
Average -- 65.87 TPY

B. PM10
Power Boiler No. 7 is a pulverized coal-fired boiler equipped with ESP control. Based on AP-42, 67% of PM emissions are PM10.
65.87 x 0.67 = 44.13 TPY

C. Sulfur Dioxide
Power Boiler No. 7 burns compliance coal. Average sulfur content was 1.1 lb/10^6 Btu in 1988 and 1989. Total coal burned in the boiler was 248,621 tons in 1989 and 230,644 tons in 1988, for an average of 239,633 TPY.
The coal averages 12,500 Btu/lb.
239,633 TPY x 2,000 x 12,500 Btu/lb = 5.99x10^{12} Btu/yr
5.99x10^{12} Btu x 1.1 lb/10^6 Btu / 2,000 = 3,294.5 TPY

D. Nitrogen Oxides

AP-42 emission factor for dry-bottom pulverized coal boiler: 21 lb/ton.
Based on coal at 12,500 Btu/lb, this results in 0.84 lb/10^6 Btu.
Boiler is limited to 0.6 lb/10^6 Btu by NSPS. Therefore, use NSPS limit: 5.99×10^{12} Btu x 0.6 lb/10^6 Btu / 2,000 = 1,797.0 TPY

E. Carbon Monoxide

Based on compliance test, boiler limited to 93.60 lb/hr CO. Boiler oxygen monitor is set to maintain this level. This equates to emission rate of 0.092 lb/10^6 Btu.
5.99×10^{12} Btu x 0.092 lb/10^6 Btu / 2,000 = 275.5 TPY

F. Volatile Organic Compounds

From AP-42 factor, dry-bottom pulverized coal boiler: 0.07 lb/ton
239,633 TPY x 0.07 lb/ton / 2,000 = 8.39 TPY

G. Lead, Mercury, Beryllium, Arsenic, Fluorides

From EPA-450/2-88-006: Emission factors for trace elements are based on boilers equipped with ESP control.

1. Lead

Factor is 25 lb/10^{12} Btu
5.99×10^{12} Btu x 25 lb/10^{12} Btu / 2,000 = 0.075 TPY

2. Mercury

Factor is 8 lb/10^{12} Btu
5.99×10^{12} Btu x 8 lb/10^{12} Btu / 2,000 = 0.024 TPY

3. Beryllium

Factor is 3.0 lb/10^{12} Btu
5.99×10^{12} Btu x 3.0 lb/10^{12} Btu / 2,000 = 0.0090 TPY

4. Arsenic

Factor is 40.1 lb/10^{12} Btu
5.99×10^{12} Btu x 40.1 lb/10^{12} Btu / 2,000 = 0.12 TPY

5. Fluorides

From EPA-600/7-81-003a, for a dry-bottom coal-fired boiler (controlled)
Factor is 4 ng/J or 9,296 lb/10^{12} Btu
5.99×10^{12} Btu x 9,296 lb/10^{12} Btu / 2,000 = 27.84 TPY

H. Sulfuric Acid Mist

Estimate at 3% of sulfur emissions.
SO_2 = 3,294.5 TPY
Sulfur = 3,294.5 x 32/64 = 1,647.3 TPY
Sulfuric Acid Mist = 1,647.3 TPY x 98/32 x 0.03 = 151.3 TPY

III. Recovery Boiler No. 4

A. PM(TSP)

From annual emissions report, based on actual stack testing and operating hours:

1988 - 342 TPY
1989 - 194 TPY
Average - 268 TPY

B. PM10

Based on AP-42, Section 10.1, for non-direct contact recovery boiler with ESP: 75% of PM is PM10.
268 TPY x 0.75 = 201 TPY

C. Sulfur Dioxide

From NCASI draft technical bulletin, SO_2 emissions from 13 non-direct contact recovery boilers averaged 4.2 lb SO_2 per ton of pulp.

Pulp production: 1988 -- 689,388 TPY
1989 -- 696,909 TPY
Average -- 693,149 TPY

Liquor swapping currently adds an additional 95 TPD equivalent pulp production, or 34,675 TPY.
Therefore, total equivalent pulp production = 693,149 + 34,675 = 727,824 TPY
727,824 tons pulp x 4.2 lb/ton / 2,000 = 1,528.4 TPY
Prorate total emissions between the two recovery boilers based on black liquor solids (BLS) fired.

	No. 4 RB	No. 5 RB	Total	
1988 -	332,770	406,718	739,488	TPY
1989 -	340,337	415,967	756,304	TPY
Average -	336,554	411,343	747,896	TPY
	(45.0%)	(55.0%)		

Recovery Boiler No. 4: 1,528.4 TPY x 0.45 = 687.8 TPY

D. Nitrogen Oxides

From 1980 NCASI paper on NO_x emissions, NO_x emissions from three non-direct contact recovery boilers averaged 1.95 lb/ton ADUP.
Total NO_x = 727,824 TPY x 1.95 lb/ton / 2,000 = 709.6 TPY

Recovery Boiler No. 4 NO_x = 709.6 TPY x 0.45 = 319.3 TPY

E. Carbon Monoxide

Emission factor from AP-42: 11 lb/ton ADUP
Total CO = 693,149 TPY x 11 lb/ton / 2,000 = 3,812.3 TPY
Prorate total to Recovery Boiler No. 4 based on BLS fired:
3,812.3 TPY x 0.45 = 1,715.5 TPY

F. Volatile Organic Compounds

Based on NCASI Technical Bulletin No. 112, February 1981, three non-direct contact evaporator recovery boilers were tested. VOC ranged from 0.66 to 1.1 lb per ton pulp and averaged 0.83 lb/ton pulp.
Total VOC = 727,824 tons/yr pulp x 0.83/ton / 2,000 = 302.0 TPY

Recovery Boiler No. 4: 302.0 TPY x 0.45 = 135.9 TPY

G. Lead, Mercury, Beryllium, Arsenic, Fluorides

From "Application of Combustion Modifications to Industrial Combustion Equipment," EPA-600/7-79-015a. Represents one test from recovery boiler.

1. Lead

Factor is 3,900 lb/10^{12} dscf
Recovery Boiler No. 4 gas flow rate from stack test on 5/8/90 of 175,147 dscfm
175,147 dscfm x 60 min/hr x 3,900 lb/10^{12} dscf = 0.041 lb/hr
From Annual Emissions Report, Recovery Boiler No. 4 operated 8,450 hrs 1989, and 8,047 hrs in 1988, or an average of 8,249 hr/yr.
Pb = 0.041 lb/hr x 8,249 hr/yr / 2,000 = 0.17 TPY

2. Mercury

Below detectable limit.

3. Beryllium

Factor is 300 lb/10^{12} dscf
175,147 dscfm x 60 x 300/10^{12} = 0.0032 lb/hr
0.0032 lb/hr x 8,249 hr/yr / 2,000 = 0.013 TPY

4. Arsenic

Factor is <1,000 lb/10^{12} dscf
175,147 x 60 x 1,000/10^{12} = 0.011 lb/hr
0.011 lb/hr x 8,249 hr/yr / 2,000 = 0.045 TPY

5. Fluorides

Below detectable limits.

H. Sulfuric Acid Mist

Based on NCASI Technical Bulletin No. 106, April 1980. Average sulfuric acid concentration in exhaust gases of recovery boiler are reported as 0.81 ppm.

$$\frac{175{,}147\ ft^3}{min} \times \frac{60\ min}{hr} \times \frac{2{,}116.8\ lb_f}{ft^2} \times \frac{98\ lb_m\text{-}°R}{1{,}545\ ft\text{-}lb_f} \times \frac{1}{528°R} \times \frac{0.81}{10^6}$$

$$= 2.16\ lb/hr$$

2.16 lb/hr x 8,249 hr/yr / 2,000 = 8.91 TPY

I. Total Reduced Sulfur (TRS)

From annual emission reports, average TRS was 1.6 ppm in 1988 and 0.81 ppm in 1989, or average of 1.21 ppm.

$175{,}147 \times 60 \times 2{,}116.8 \times (34/1{,}545) \times (1/528) \times 1.21/10^6$
$= 1.12$ lb/hr

1.12 lb/hr x 8,249 hr/yr / 2,000 = 4.62 TPY

IV. Recovery Boiler No. 5

A. PM(TSP)

From Annual Emissions Reports, based on actual stack testing and operating hours:

1989 - 152 TPY
1988 - 35.4 TPY
Avg. - 93.7 TPY

B. PM10

Based on AP-42, Section 10.1, for non-direct contact recovery boiler with ESP: 75% of PM is PM10.
93.7 TPY x 0.75 = 70.3 TPY

C. Sulfur Dioxide

From Recovery Boiler No. 4 calculations:
1,528.4 TPY x 0.55 = 840.6 TPY

D. Nitrogen Oxides

Based on Recovery Boiler No. 4 calculations:
Recovery Boiler No. 5 NO_x = 709.6 TPY x 0.55 = 390.3 TPY

E. Carbon Monoxide

Based on Recovery Boiler No. 4 calculations:
3,812.3 TPY x 0.55 = 2,096.8 TPY

F. Volatile Organic Compounds

Based on Recovery Boiler No. 4 calculations:
302.0 TPY x 0.55 = 166.1 TPY

G. Lead, Mercury, Beryllium, Arsenic, Fluorides

From "Application of Combustion Modifications to Industrial Combustion Equipment," EPA-600/7-79-015a. Represents one test from recovery boiler.

1. Lead

Factor is 3,900 lb/10^{12} dscf
Recovery Boiler No. 5 gas flow rate from stack test 1/10/90 = 139,548 dscfm
139,548 dscfm x 60 min/hr x 3,900 lb/10^{12} dscf = 0.033 lb/hr
From Annual Emissions Report, Recovery Boiler No. 5 operated 8,434 hrs in 1989 and 7,661 hrs in 1988, or an average of 8,048 hr/yr.
Pb = 0.033 lb/hr x 8,048 hr/yr / 2,000 = 0.13 TPY

2. Mercury

Below detectable limit.

3. Beryllium

Factor is 300 lb/10^{12} dscf
139,548 dscfm x 60 x 300/10^{12} = 0.0025 lb/hr
0.0025 lb/hr x 8,048 hr/yr / 2,000 = 0.010 TPY

4. Arsenic

Factor is <1,000 lb/10^{12} dscf
139,548 x 60 x 1,000/10^{12} = 0.0084 lb/hr
0.0084 lb/hr x 8,048 hr/yr / 2,000 = 0.034 TPY

5. Fluorides

Below detectable limits.

H. Sulfuric Acid Mist

Based on NCASI Technical Bulletin No. 106, April 1980. Average sulfuric acid concentration in exhaust gases of recovery boiler are reported as 0.81 ppm.

$$\frac{139{,}548\ ft^3}{min} \times \frac{60\ min}{hr} \times \frac{2{,}116.8\ lb_f}{ft^2} \times \frac{98\ lb_m\text{-}°R}{1{,}545\ ft\text{-}lb_f} \times \frac{1}{528°R} \times \frac{0.81}{10^6}$$

$$= 1.72\ lb/hr$$

1.72 lb/hr x 8,048 hr/yr / 2,000 = 6.92 TPY

I. Total Reduced Sulfur

From Annual Emission Reports, average TRS was 1.82 ppm in 1989 and 1.7 ppm in 1988, or average of 1.76 ppm.

$139,548 \times 60 \times 2116.8 \times (34/1545) \times (1/528) \times 1.76/10^6$
$= 1.30$ lb/hr

1.30 lb/hr x 8,048 hr/yr / 2,000 = 5.23 TPY

V. Smelt Dissolving Tank No. 4

A. PM

From Annual Emission Reports, based on stack test and operating hours:

1989 - 24.7 TPY
1988 - 99.4 TPY
Avg. - 62.1 TPY

B. PM10

Smelt Dissolving Tank No. 4 is controlled by wet scrubber. Based on AP-42, Table 10.1-7, PM10 is 89.5% of PM emissions.

62.1 TPY x 0.895 = 55.6 TPY

C. SO_2

AP-42 factor is 0.2 lb/ton ADUP, uncontrolled. Conservatively, we have assumed 50% control for the wet scrubber.
Total SO_2 emissions = 727,824 tons x 0.2 lb/ton x 0.5 / 2,000
= 36.4 TPY
From Recovery Boiler No. 4 calculations, 45% of production through this boiler: 36.4 TPY x 0.45 = 16.4 TPY

D. TRS

From Annual Emission Reports, based on stack test and operating hours for 1989; based on permit limits for 1988:

1989 - 4.35 TPY
1988 - 8.90 TPY
Avg. - 6.63 TPY

VI. Smelt Dissolving Tank No. 5

A. PM

From Annual Emission Reports, based on stack test and operating hours:

1989 - 24.0 TPY
1988 - 25.3 TPY
Avg. - 24.7 TPY

B. PM10

Smelt Dissolving Tank No. 4 is controlled by wet scrubber. Based on AP-42, Table 10.1-7, PM10 is 89.5% of PM emissions.

24.7 TPY x 0.895 = 22.1 TPY

C. SO_2

From Smelt Dissolving Tank No. 4 calculations:

36.4 x 0.55 = 20.0 TPY

D. TRS

Based on stack test in 1988 and actual hours of operation in 1988 and 1989:

Stack test result = 0.11 lb/hr

Operating hours--1988 - 7,661 hrs
1989 - 8,434 hrs
Avg. - 8,048 hrs

Average TRS emissions = 0.11 lb/hr x 8,048 hr/yr / 2,000 = 0.44 TPY

VII. Lime Kiln No. 4

Since new lime kiln started operation in December 1989, there is no historical operating data. Therefore, actual emissions are assumed equal to permitted emissions:

PM -- 43.5 lb/hr, 190.0 TPY
PM10 -- 38.5 lb/hr, 168.2 TPY
SO_2 -- 26.8 lb/hr, 117.1 TPY
NO_x -- 187.7 lb/hr, 819.9 TPY
CO -- 78.8 lb/hr, 29.8 TPY
VOC -- 15.2 lb/hr, 44.7 TPY
TRS -- 2.63 lb/hr, 11.5 TPY

NET EMISSIONS INCREASE
DUE TO NEW BATCH DIGESTER AND BROWN STOCK WASHER

Net emission increases were calculated using the criteria in FAC 17-2.500 (2)(e). In all instances, future actual emissions will remain within the current permitted levels.

I. Power Boiler No. 5

PB No. 5, a combination oil/bark/woodwaste-fired boiler, will experience an increase in steam production, but future operation will remain within existing permitted levels. All of the increase is assumed to be from oil burning. The increase is calculated as 22.92 barrels per day of oil for 355 days per year, or 341,737 gallons per year.

A. Particulate Matter (TSP)
AP-42 factor is (10S+3) lb/1000 gal. (uncontrolled)
10(2.5)+3 = 28 lb/1000 gal
341,737 gal/yr x 28 lb/1000 gal / 2000 = 4.8 TPY

B. PM10
No. 5 Power Boiler is controlled with an ESP. AP-42 contains particle size information for oil-fired boiler equipped with ESP. The data show that 63% of PM is PM10.
4.8 TPY x 0.63 = 3.0 TPY

C. Sulfur Dioxide
Fuel analyses show that actual sulfur content in the fuel oil was 2.5% the last two years. Using AP-42 emission factor of 157 S pounds per 1,000 gal of fuel for utility boiler where S is the percent of sulfur content in fuel oil:

SO_2 emission factor = 157S lb/10^3 gal, S = 2.5%

SO_2 = 341,737 gal x 157(2.5)/10^3 gal / 2,000 = 67.1 TPY

D. Nitrogen Oxides
AP-42: 67 lb/10^3 gal
341,737 gal x 67/10^3 / 2,000 = 11.5 TPY

E. Carbon Monoxide
AP-42: 5 lb/10^3 gal
341,737 gal x 5/10^3 / 2,000 = 0.9 TPY

F. Volatile Organic Compounds (non-methane)
AP-42: 0.76 lb/10^3 gal
341,737 gal x 0.76 lb/10^3 gal / 2,000 = 0.13 TPY

G. Trace Elements (Lead, Mercury, Beryllium, Arsenic, Fluorides)
From "Toxic Air Polluted Emission Factors--A Compilation for Selected Air Toxic Compounds and Sources," EPA-450/2-88-006.

1. Lead
Factor is 8.9 lb/10^{12} Btu (uncontrolled)
Increased fuel usage = 341,737 gal
Heating value = 145,000 Btu/gal
Heat input = 341,737 x 145,000
= 0.05x10^{12} Btu/yr
Pb = 0.05x10^{12} Btu/yr x 8.9 lb/10^{12} Btu / 2,000
= 0.00022 TPY

2. Mercury
Factor is 2.4 lb/10^{12} Btu (controlled by ESP)
Hg = 0.05x10^{12} x 2.4/10^{12} / 2,000 = 0.00006 TPY

3. Beryllium
Factor is 0.59 lb/10^{12} Btu (controlled by ESP)
Be = 0.05x10^{12} x 0.59/10^{12} / 2,000 = 0.000015 TPY

4. Arsenic
Factor is 2.28 lb/10^{12} Btu (controlled by ESP)
As = 0.05x10^{12} x 2.28/10^{12} / 2,000 = 0.00006 TPY

5. Fluorides
From "Emissions Assessment of Conventional Stationary Combustion Systems, Vol V: Industrial Combustion Sources," EPA-600/7-81-003a.
Factor is 2.7 pg/J = 6.27 lb/10^{12} Btu (uncontrolled)
F = 0.05x10^{12} x 6.27/10^{12} / 2,000 = 0.00016 TPY

H. Sulfuric Acid Mist
Sulfuric acid mist is estimated as 3% of sulfur emissions
SO_2 = 67.1 TPY
Sulfur = 67.1 x 32/64 = 33.55 TPY
Sulfuric acid mist = 33.55 x 98/32 x 0.03 = 3.1 TPY

II. Power Boiler No. 7

Power Boiler No. 7 will experience an 8.0% increase in steam production, which results in approximately 56.0 additional tons of coal being burned per day. Actual emissions will increase by 8.0%.

Pollutant	Current Actual Emissions (TPY)	Increase in Actual Emissions (TPY)
PM(TSP)	65.87	5.3
PM10	44.13	3.53
SO_2	3,294.5	263.6
NO_x	1,797.0	143.76
CO	275.5	22.04
VOC	8.39	0.67
Pb	0.075	0.006
Hg	0.024	0.0019
Be	0.0090	0.00072
As	0.12	0.010
Fl	27.84	2.23
H_2SO_4	151.3	12.1

III. Recovery Boiler No. 4

The actual net increase in fuel input to the recovery boilers will be the equivalent of 155 tons per day of pulp. This is a 7.7% increase above current operating rates.

A. PM(TSP)
   Current actual = 268 TPY
   268 x 0.077 = 20.6 TPY

B. PM10
   20.6 x 0.75 = 15.5 TPY

C. SO_2
   687.8 x 0.077 = 53.0 TPY

D. NO_x
   319.3 x 0.077 = 24.6 TPY

E. CO
   1,715.5.9 x 0.077 = 132.1 TPY

F. VOC
   135.9 x 0.077 = 10.5 TPY

G. Trace Metals
   Pb--0.17 x 0.077 = 0.013 TPY
   Hg--N/A
   Be--0.013 x 0.077 = 0.0010 TPY
   As--0.045 x 0.077 = 0.0035 TPY
   Fl--N/A

H. Sulfuric Acid Mist
   8.91 x 0.077 = 0.69 TPY

I. TRS
   4.62 x 0.077 = 0.36 TPY

IV. Recovery Boiler No. 5

Similar to Recovery Boiler No. 4, operation of Recovery Boiler No. 5 will increase 7.7% over present operation.

A. PM(TSP)
93.7 x 0.077 = 7.2 TPY

B. PM10
7.2 x 0.75 = 5.4 TPY

C. SO_2
840.6 x 0.077 = 64.7 TPY

D. NO_x
390.3 x 0.077 = 30.1 TPY

E. CO
2,096.8 x 0.077 = 161.5 TPY

F. VOC
166.1 x 0.077 = 12.8 TPY

G. Trace Metals
Pb--0.13 x 0.077 = 0.010 TPY
Hg--N/A
Be--0.010 x 0.077 = 0.00077 TPY
As--0.034 x 0.077 = 0.0026 TPY
Fl--N/A

H. Sulfuric Acid Mist
6.92 x 0.077 = 0.53 TPY

I. TRS
5.23 x 0.077 = 0.40 TPY

V. Smelt Dissolving Tank No. 4 and No. 5

The smelt tanks will experience the same increase over current operating rates as the recovery boilers (7.7%).

Pollutant	SDT No. 4 (TPY)		SDT No. 5 (TPY)	
	Current	Increase	Current	Increase
PM	62.1	4.8	24.7	1.9
PM10	55.6	4.3	22.1	1.7
SO_2	16.4	1.3	20.0	1.5
TRS	6.63	0.51	0.44	0.03

VI. Lime Kiln No. 4

Since there is no historic operating data from the new lime kiln, the present and future actual emissions are assumed to be the current permitted allowables.

EMISSION REDUCTIONS -- POWER BOILER NO. 4

Base actual emissions on last 2 years (1985 - 1986) of sustained boiler operation.

A. Particulate Matter (TSP)

1986 - Stack tests of 2/18/86 and 10/28/86 - 65.8 lb/hr avg
Operating days = 264

PM = 264 days x 24 hr/day x 65.8 lb/hr / 2,000 lb/ton
= 208.5 TPY

1985 - Base on 1985 stack test - 75.9 lb/hr
Operating days = 288

PM = 288 x 24 x 75.9 / 2,000 = 262.3 TPY

Avg. = 235.4 TPY

B. PM10

Power Boiler No. 4 was controlled with mechanical collectors and fly ash injection. AP-42 states that PM10 is 79% of PM emissions.
235.4 TPY x 0.79 = 186.0 TPY

C. SO_2

1. Bark/Wood
Avg. = 78,367 tons/yr burned
Dry basis--moisture 50% -- 78,367 x 0.5 = 39,183.5 tons
AP-42: 0.4 lb/ton dry
39,183.5 tons x 0.4 lb/ton / 2,000 = 7.8 TPY

2. Fuel Oil
1986 - 764,000 gal @ 2.5% S
1985 - 4,384,000 gal @ 1.97% S
AP-42: SO_2 = 157 S lb/1,000 gal

1986 - 764,000 x 157(2.5)/1,000 / 2,000 = 149.9 TPY
1985 - 4,384,000 x 157(1.97)/1,000 / 2,000 = 678.0 TPY
Avg. - 414.0 TPY

3. Total
7.8 TPY + 414.0 TPY = 421.8 TPY

D. Nitrogen Oxides

1. Fuel Oil Burning
AP-42: 67 lb/10^3 gal
Average of 2.574×10^6 gal/yr burned
2.574×10^6 gal x $67/10^3$ / 2,000 = 86.2 TPY

2. Bark Burning
   From AP-42: 2.8 lb/ton bark
   78,367 TPY x 2.8 lb/ton / 2,000 = 109.7 TPY

3. Total
   86.2 + 109.7 = 195.9 TPY

E. Carbon Monoxide

1. Fuel Oil Burning
   AP-42: 5 $lb/10^3$ gal
   2.574×10^6 gal x $5/10^3$ / 2,000 = 6.4 TPY

2. Bark Burning
   From NCASI Technical Bulletin No. 109, September 1980, four wood-waste boilers were tested continuously for CO. Boilers A and C operated at about 140,000 lb/hr steam, which is similar to Power Boiler No. 4 operation. The 1-hour CO tests ranged from 0.31 to 4.0 $lb/10^6$ Btu and averaged 1.84 $lb/10^6$ Btu. This average factor was used to calculate actual CO emissions:
   78,367 tons bark x 2,000 lb/ton x 4,250 Btu/lb
   = 0.67×10^{12} Btu/yr

   0.67×10^{12} Btu/yr x 1.84 $lb/10^6$ Btu / 2,000 = 616.4 TPY

3. Total
   6.4 + 616.4 = 622.8 TPY

F. Volatile Organic Compounds

1. Fuel Oil Burning
   AP-42: 0.76 $lb/10^3$ gal
   2.574×10^6 gal x 0.76 $lb/10^3$ gal / 2,000 = 1.0 TPY

2. Bark Burning
   AP-42: 1.4 lb/ton bark
   78,367 TPY x 1.4 lb/ton / 2,000 = 54.9 TPY

3. Total
   1.0 + 54.9 = 55.9 TPY

G. Lead, Mercury, Beryllium, Arsenic, Fluorides

1. Fuel Oil Burning
   From "Toxic Air Pollutant Emission Factors - A Compilation for Selected Air Toxic Compounds and Sources," EPA-450/2-88-006.
   a. Lead
      Factor is 8.9 $lb/10^{12}$ Btu (uncontrolled)
      Fuel usage = 2.574×10^6 gal
      Heating value = 145,000 Btu/gal
      Heat input = 2.574×10^6 x 145,000
      = 0.373×10^{12} Btu/yr

Pb = 0.373×10^{12} Btu/yr x 8.9 lb/10^{12} Btu / 2,000
= 0.0017 TPY

b. Mercury
Factor is 3.2 lb/10^{12} Btu (controlled by multiclone)
Hg = 0.373×10^{12} x 3.2/10^{12} / 2,000 = 0.00060 TPY

c. Beryllium
Factor is 2.65 lb/10^{12} Btu (controlled by multiclone)
Be = 0.373×10^{12} x 2.65/10^{12} / 2,000 = 0.00049 TPY

d. Arsenic
Factor is 9.31 lb/10^{12} Btu (controlled by multiclone)
As = 0.373×10^{12} x 9.31/10^{12} / 2,000 = 0.00174 TPY

e. Fluorides
From "Emissions Assessment of Conventional Stationary Combustion Systems, Vol V: Industrial Combustion Sources," EPA-600/7-81-003a.
Factor is 2.7 pg/J = 6.27×10^{12} Btu (uncontrolled)
Fl = 0.373×10^{12} x 6.27/10^{12} / 2,000 = 0.00117 TPY

2. Bark Burning
All factors based on EPA-600/7-81-003a, for a controlled wood-fired stoker boiler. Emission factor is increased by 50% to account for only multiclone control on boiler.
a. Lead
Factor is 50 pg/J = 116 lb/10^{12} Btu x 1.5
= 174 lb/10^{12}Btu
0.67×10^{12} Btu/yr x 174 lb/10^{12} Btu / 2,000 = 0.058 TPY

b. Mercury
Not measured--no emission factor.

c. Beryllium
Factor is <1 pg/J, or <2.3 lb/10^{12} Btu x 1.5
= 3.5 lb/10^{12} Btu
0.67×10^{12} Btu/yr x 3.5 lb/10^{12} Btu / 2,000
= 0.00117 TPY

d. Arsenic
Factor is 12 pg/J = 27.9 lb/10^{12} Btu x 1.5
= 41.9 lb/10^{12} Btu
0.67×10^{12} Btu/yr x 41.9 lb/10^{12} Btu / 2,000 = 0.014 TPY

e. Fluorides
Not measured--no emission factor available.

3. Totals

a. Lead:	0.0017	+	0.058	= 0.060 TPY
b. Mercury:	0.00060	+	0	= 0.00060 TPY
c. Beryllium:	0.00049	+	0.00117	= 0.00166 TPY
d. Arsenic:	0.00174	+	0.014	= 0.0157 TPY
e. Fluorides:	0.00117	+	0	= 0.00117 TPY

H. Sulfuric Acid Mist

Sulfuric acid mist is estimated at 3% of sulfur emissions

SO_2 = 421.8 TPY

Sulfur = 421.8 x 32/64 = 210.9 TPY

Sulfuric acid mist = 210.9 x 98/32 x 0.03 = 19.4 TPY