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4. PROJECT EMISSIONS

As presented in Section 2, Indeck - Elwood, LLC is proposing to construct and operate two (2) bituminous coal and supplemental fuel (i.e. petcoke and waste coal) fired CFB boilers. Additional emission sources include material handling operations, an auxiliary boiler, two wet cooling towers, and two emergency diesel engines. Annual potential to emit (PTE) rates for PSD regulated pollutants were estimated based on maximum fuel input rates. Potential emissions estimates were conducted based upon unlimited operation of the CFB boilers for the entire year (8,760 hours). Table 3-1 in Section 3 provided facility-wide potential annual emissions for the Project. A summary of the estimating methodologies and controls used to estimate emissions from all sources is provided below. Source specific emissions data and facility-wide potential emissions calculations are presented in detail in Appendix B.

4.1 CFB Boilers

4.1.1 Baseload Operation

The CFB boilers will typically operate at operating loads between 50 percent and full load. Performance data specifying emissions of NO_x, SO_2, PM/PM_{10}, CO, VOM, sulfuric acid mist, and ammonia (NH_3) were obtained from the CFB boiler vendor. Emissions data were provided at base (100%) load, 75 percent load, and 50 percent load. Short-term emission rates (lb/MMBtu) for CO and VOMs increase at reduced operating loads but maximum pound per hour emissions for all criteria pollutants are highest at full load. These emissions data are consistent with the BACT and LAER emission levels determined in Section 5. The proposed BACT emission levels will be maintained when firing bituminous coal or a combination of bituminous coal and petcoke and or waste coal. Therefore, fuel mix will not affect potential emissions from the Project.

Emissions of all metallic HAPs, except for mercury, were estimated in accordance with procedures defined in EPA's *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report To Congress* (02/1998). These procedures allow for estimation of emissions based upon boiler type (pulverized coal, CFB, etc.), coal type (bituminous, anthracite, etc.), and specific add-on controls (SNCR, baghouse, etc.). Therefore, these procedures can provide a HAP specific emission factor for the specific boiler configuration proposed for the project. HAP emissions for the Project were estimated based upon worst case HAP concentrations in bituminous coal and EPA specified emission modification factors (EMFs) for a CFB boiler equipped with SNCR and a baghouse. Emissions of non-metallic HAPs were estimated using emission factors provided in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion).

Emissions of mercury were estimated based upon the case-by-case MACT analysis as described in Section 5.2. The IEPA established the MACT floor for mercury emissions from bituminous coal fired CFB boilers with the issuance of the Enviropower permit in July 2001. The Project will comply with the MACT floor control levels established in the Enviropower permit recently issued for the Benton, IL coal project.

Potential annual emissions from the boilers were determined based upon the maximum estimated pound per hour emission rate for each pollutant and 8,760 operating hours per year. Detailed emission calculations for all criteria pollutants and HAPs are provided in Appendix B, Table B-2.

4.1.2 Startup Operation

To initiate startup of the boilers, natural gas is initially fired to raise the CFB bed temperature to a minimum of 900°F so that coal firing can commence in the CFB boiler. Once coal firing is commenced in the boilers, there is a transition period during which the feed rate of coal is gradually increased and the natural gas firing rate is gradually decreased until the CFB boiler is operating entirely on coal. Firing with coal only is achieved at approximately 40 percent of full load. The coal firing rate is then gradually increased until the minimum operating load of 50 percent of full load is achieved. Therefore, startup of the CFB boilers will be accomplished during three phases: initial firing on natural gas only; simultaneous firing of natural gas and coal; and firing of coal only until minimum operating load is achieved.

During startup operation, short-term emission rates of PSD regulated pollutants may exceed their respective proposed BACT limits (Section 5). For the purposes of this application, startup is defined as the period during which the CFB boiler load is raised from 0 to 50 percent of MCR (maximum continuous rating) and during which the CFB boiler is expected to exceed the requested BACT emission limits.

An analysis was conducted to quantify startup emissions from a cold startup (boiler at ambient temperature) until the boiler reaches 50 percent of MCR. This analysis evaluated each of the three phases of startup operation as described above. A detailed description of each of these phases is provided below.

PHASE 1: An initial seven (7) hour heat up period during which natural gas is fired to heat the furnace to approximately 900°F. Over the first three hours of this seven hour period, the natural gas flow rate to the startup burners is gradually increased until the heat input associated with the startup fuel flow is approximately 15 percent of the maximum full load CFB boiler heat input. The flow rate of natural gas to the startup burners is then kept constant at this rate for the next four hours as the furnace continues to heat up.

PHASE 2: Phase 2 begins with initial firing of coal in the boiler after the minimum coal firing temperature of 900°F is achieved. The feed rate of coal is then gradually increased and the natural gas feed rate is gradually decreased until the CFB boiler is operating entirely on coal. This transition takes approximately four hours. At the end of this transition period, the CFB boiler is operating entirely on coal at approximately 40 percent of MCR.

PHASE 3: An increase in CFB boiler load to 50 percent of MCR accomplished by increasing the coal feed rate.

During startup operation, emissions of PSD regulated pollutants may be elevated above proposed BACT emission levels for several reasons. These reasons include the following:

- NO_x emissions may be increased since the SNCR system will not be effective due to the low boiler temperature during startup. The SNCR requires a minimum operating temperature of 1,350°F with an optimum temperature of 1,600°F. The proposed NO_x BACT emission rate will be achieved at 50 percent of MCR.

- CO and VOC emissions will be increased due to the low temperature in the furnace during startup and the smoldering of residual solid fuel particles that may be present in the bed.

- SO_2 emissions will be increased during Phase 2 when coal is initially fired in the boilers due to the low furnace temperature limiting injection of limestone into the bed. At the beginning of Phase 2 with the furnace at 900°F, very little, if any, limestone will calcine and consequently, no significant amount of sulfur capture will occur within the furnace. As the furnace heats up, more limestone will calcine thereby increasing the capture of sulfur within the furnace. At the end of Phase 3, the SO_2 emission level will reach the proposed BACT emission rate. SO_2 emissions during Phase I will be lower than the proposed SO_2 BACT rate due to the firing of natural gas.

PM/PM_{10} emissions during all phases of startup will be less than or equal to the proposed BACT emission rate due to the firing of natural gas and the presence of the baghouse.

An estimate was conducted of criteria pollutant emissions during each hour of a twelve-hour cold start to determine if startup emissions would impact the potential annual emissions for the Project. The total criteria pollutant emissions estimated during a 12-hour cold start were compared with the total criteria pollutant emissions during 12 hours of full load operation. The results of this analysis show that startup operation does not increase potential annual emissions of any criteria pollutant. A detailed analysis of startup emissions is provided in Table B-2a in Appendix B.

4.2 Material Handling

The Project will include equipment for the handling of coal, petcoke, limestone, and ash. All material handling equipment will be enclosed, including buildings around the coal and limestone storage piles, and all stack emission points within the material handling system will employ fabric filters. Aggregate wetting will be utilized to minimize the potential for fugitive dust emissions from the enclosures.

Provided in Table 4-1 below is a list of the material handling emission sources. Each source is noted as either a point or fugitive emission source. Process schematics depicting each of these emission sources are provided in Appendix C. Appendix D contains a facility plot plan drawing including an overall view of the material handling system.

Since enclosures will be used throughout the material handling processes for the Project, fugitive dust emissions will be minimal. Two fugitive dust sources have been identified; bed ash loadout from the bed ash silos and fly ash loadout from the fly ash silos. Both the bed ash and fly ash loadout operations will use a dust suppression system to control wet mixers to increase the moisture content of the ash prior to loading into trucks or railcars. The railcars will be covered (or another equivalently effective means will be utilized) to prevent dust emissions during transit to the ash disposal location.

Table 4-1: Material Handling Emission Sources

Source ID	Description	Dust Control	Point or Fugitive?
F-001	Railcar Unloading	Fabric Filter	Point
F-002	Live Storage Building	Building, Wetting & Fabric Filter	Point
F-003	Dead Storage Building	Building & Wetting	Point (General Ventilation)
F-101	Limestone Reclaim	Fabric Filter	Point
F-102	Transfer House	Fabric Filter	Point
F-103	Crusher House	Fabric Filter	Point
F-104	Unit #1 Tripper Floor	Fabric Filter	Point
F-105	Unit #2 Tripper Floor	Fabric Filter	Point
F-201-T1	Unit #1 Day Silo	Fabric Filter	Point
F-201-T2	Unit #2 Day Silo	Fabric Filter	Point
F-301	Limestone In-Feed Silo	Fabric Filter	Point
F-302-T1	Limestone Preparation #1	Fabric Filter	Point
F-302-T2	Limestone Preparation #2	Fabric Filter	Point
F-302-T3	Limestone Preparation #3	Fabric Filter	Point
F-303-T1	Limestone Dryer/Mill #1	Fabric Filter	Point
F-303-T2	Limestone Dryer/Mill #2	Fabric Filter	Point
F-303-T3	Limestone Dryer/Mill #3	Fabric Filter	Point
F-202	Unit #1 Surge Hopper	Fabric Filter	Point
F-203	Unit #2 Surge Hopper	Fabric Filter	Point
F-204	Unit #1 Bed Ash Silo	Fabric Filter	Point
F-205	Unit #2 Bed Ash Silo	Fabric Filter	Point
F-206A	Fly Ash Blower Exhaust #1	Fabric Filter	Point
F-206B	Fly Ash Blower Exhaust #2	Fabric Filter	Point
F-207A	Fly Ash Blower Exhaust #3	Fabric Filter	Point
F-207B	Fly Ash Blower Exhaust #4	Fabric Filter	Point
F-208	Unit #1 Fly Ash Silo	Fabric Filter	Point
F-209	Unit #2 Fly Ash Silo	Fabric Filter	Point
F-210	Bed Ash Loadout	Wet Mixer	Fugitive
F-211	Fly Ash Loadout	Wet Mixer	Fugitive

The Project will fully enclose the fuel and limestone storage piles to minimize fugitive emissions. The material handling operations within the storage buildings will employ wetting at transfer points to reduce the generation of fugitive dust. Since the piles will be completely enclosed within buildings, there will be no wind generated fugitive dust emissions. Any fugitive dust generated during reclaim operations or other material handling activities within the live storage building will be vented through two fabric filter points. Fugitive emissions generated in the dead storage building, will be emitted through general ventilation roof vents.

The fabric filters employed on the exhaust systems throughout the material handling and storage operations will reduce particulate loading in the exhaust to less than 0.005 grains per standard cubic foot (gr/scf).

Emissions from material transfer dropping operations were estimated in accordance with Equation 1 in AP-42 Section 13.2.4 (Aggregate Handling & Storage Piles). These operations include railcar unloading, bed ash loadout, fly ash loadout, and various transfer points throughout the live and dead storage buildings. Emissions were estimated based upon material property data provided in AP-42 and the maximum material usage rates for the Project.

Bulldozers in combination with scrappers/reclaimer will be utilized to reclaim coal and limestone in the live and dead storage buildings for delivery to the boilers. Emissions from bulldozing were estimated in accordance with procedures found in AP-42 Section 11.9 (Western Surface Coal Mining). Emissions were estimated based upon the maximum number of expected hours of bulldozing operations.

Emissions from the live storage building were determined from the combined emissions from material transfer and bulldozing and a 99.9 percent control efficiency of the fabric filters through which the live storage building will be exhausted.

Emissions from the dead storage building also were determined from material transfer and bulldozing with 95 percent control from material wetting and the building enclosure.

Emissions from the fabric filters throughout the material handling system were based upon the controlled particulate concentration of 0.005 gr/scf or less (many of the emission points will be controlled down to 0.001 gr/scf), the maximum exhaust flow rate for each exhaust point (scfh), and 8,760 operating hours per year.

The material handling operations will include three natural gas fired limestone drying mills. The combustion of natural gas will result in emissions of NO_x, CO, SO_2, and VOM. Emissions of these pollutants were determined from vendor specifications. PM/PM_{10} emissions were determined based upon the controlled particulate concentration of 0.001 gr/scf and the maximum exhaust flow rate (scfh). Potential emissions of all pollutants were estimated based upon maximum operation for 8,760 hr/yr.

Detailed emission calculations for the material handling operations are provided in Appendix B, Tables B-3 and B-4.

4.3 Plant Roadways

Vehicle traffic along plant roadways will generate fugitive dust emissions, primarily due to truck travel for the limestone hauling. To minimize these fugitive dust emissions, all plant roadways will be paved. Additional fugitive dust mitigation measures will also be employed such as road wetting and/or sweeping.

Emissions from truck travel over plant roadways were estimated in accordance with procedures provided in AP-42 Section 13.2.1 (Paved Roads). Detailed emission calculations for truck travel over paved roadways are provided in Appendix B, Table B-5.

4.4 Cooling Towers

The Project will include two (2) twelve-cell wet cooling towers. A small fraction of the tower circulating water will be entrained in the air leaving the tower and will be discharged to the atmosphere as small droplets called "drift". The drift water contains dissolved solids. As the drift water evaporates, the dissolved solids form particulate matter (PM/PM_{10}) that is emitted to the atmosphere.

PM/PM_{10} emissions from the cooling towers were estimated based upon vendor provided maximum circulating water flow rates, drift, and maximum circulating water total dissolved solids (TDS) concentration. The cooling tower drift will be limited to no greater than 0.0005 percent of the total circulating water flow. The cooling tower design maximum TDS value will be 3,000 ppmw. Potential PM/PM_{10} emissions were estimated using these maximum values and 8,760 operating hours per year.

Detailed emission calculations for the cooling tower can be found in Appendix B, Table B-6.

4.5 Miscellaneous Combustion Sources

The Project will include a natural gas fired auxiliary boiler and two (2) small emergency diesel engines (fire pump and boiler cool down pump). Potential emissions from the 99 MMBtu/hr natural gas fired auxiliary boiler were estimated based upon the maximum heat input, the proposed annual operating hour restriction of 2500 hr/yr, the NO_x BACT emission rate of 0.037 lb/MMBtu, and emission factors for the other pollutants in AP-42, Section 1.4 (Natural Gas Combustion). Potential emissions from the two emergency diesel engines were estimated based upon a maximum of 500 operating hours per year, the maximum heat input to each engine, and emission factors in AP-42, Section 3.3 (Gasoline and Diesel Industrial Engines).

Detailed emission calculations for the miscellaneous combustion sources can be found in Appendix B, Table B-7.

4.6 Facility-Wide Emissions Summary

A summary of plant wide potential emissions of PSD regulated pollutants is provided in Table 4-2 below.

Table 4-2: Facility-Wide Potential Emissions Summary

Pollutant	Boilers	Paved Roads	Misc Point PM Sources	Misc Fugitive PM Sources	Auxiliary Boiler	Boiler Cool Down Pump Engine	Fire Pump Engine	Cooling Tower	Facility Totals
NOx	2,559.7		11.5		9.9	1.3	1.3		2,583.7
SO2	4,607.4				0.7	0.02	0.02		4,608.2
PM (TSP)	384.0	3.2	9.9	1.3	1.2	0.01	0.01	8.4	408.1
PM10	384.0	0.6	9.9	0.3	1.2	0.01	0.01	8.4	404.4
CO	2,815.6		31.5		12.4	0.1	0.1		2,859.7
VOC	102.4		3.2		2.5	0.01	0.01		108.0
Sulfuric Acid Mist	10.2				0.1	0.003	0.003		10.4
Lead	0.31								0.31
Beryllium	0.004								0.004
Mercury	0.10								0.10
Fluorides	50.2								50.2

NOTES:
1. Boiler PTE represents combined emissions from both boilers
2. Auxiliary boiler PTE based 2500 hours per year operation.
3. Diesel engines (Fire Pump and Boiler Cool Down Pump engines) PTE based on 500 hours per year operation.

Indeck Elwood Energy Center
Facility Wide Potential Emissions
Table B-1

Pollutant	Boilers	Paved Roads	Misc Point PM Sources	Misc Fugitive PM Sources	Auxiliary Boiler	Boiler Cool Down Pump Engine	Fire Pump Engine	Cooling Tower	Facility Totals
NOx	2,559.7		11.5		9.9	1.3	1.3		**2,583.7**
SO2	4,607.4				0.7	0.02	0.02		**4,608.2**
PM (TSP)	384.0	3.2	9.9	1.3	1.2	0.01	0.01	8.4	**408.1**
PM10	384.0	0.6	9.9	0.3	1.2	0.01	0.01	8.4	**404.4**
CO	2,815.6		31.5		12.4	0.1	0.1		**2,859.7**
VOC	102.4		3.2		2.5	0.01	0.01		**108.0**
Sulfuric Acid Mist	10.2				0.1	0.003	0.003		**10.4**
Lead	0.31								**0.31**
Beryllium	0.004								**0.004**
Mercury	0.10								**0.10**
Fluorides	50.2								**50.2**

NOTES:
1. Boiler PTE represents combined emissions from both boilers
2. Auxiliary boiler PTE based 2500 hours per year operation.
3. Diesel engines (Fire Pump and Boiler Cool Down Pump engines) PTE based on 500 hours per year operation.

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CFB Boiler Emissions and Operating Data

Table B-2

Parameter		Operating Load		
		100%	75%	50%
Coal Consumption:	klbs/hr	250.5	193.0	135.1
Coal Specification:	Btu/lb	11,666	11,666	11,666
Maximum Heat Input:	MMBtu/hr	2,922	2,251	1,576
Stack Exhaust Temp	°F	280	280	280
Stack Volumetric Exhaust Flow:	ACFM	921,602	709,968	496,923
Stack Exit Diameter:	"	216	216	216
Stack Exhaust Exit Velocity:	fps	60.4	46.5	32.5
	m/s	18.40	14.17	9.92
NOx Emissions:	lb/MMBtu	0.10	0.10	0.10
	lb/hr	292.2	225.1	157.6
	g/s	36.82	28.36	19.85
	tpy	1,279.8	985.9	690.1
SO_2 Emissions:	lb/MMBtu	0.18	0.18	0.18
	lb/hr	526.0	405.2	283.6
	g/s	66.27	51.05	35.73
	tpy	2,303.7	1,774.7	1,242.1
CO Emissions:	lb/MMBtu	0.11	0.14	0.19
	lb/hr	321.4	321.4	293.3
	g/s	40.50	40.50	36.95
	tpy	1,407.8	1,407.8	1,284.6
TSP/PM10 Emissions	lb/MMBtu	0.015	0.015	0.015
	lb/hr	43.8	33.8	23.6
	g/s	5.52	4.25	2.98
	tpy	192.0	147.9	103.5
VOC Emissions:	lb/MMBtu	0.004	0.005	0.007
	lb/hr	11.7	11.7	11.7
	g/s	1.47	1.47	1.47
	tpy	51.2	51.2	51.2
H_2SO_4 Emissions:	lb/MMBtu	0.0004	0.0004	0.0004
	lb/hr	1.2	0.9	0.6
	g/s	0.15	0.11	0.08
	tpy	5.1	3.9	2.8
Ammonia Emissions:	lb/MMBtu	0.0076	0.0076	0.0202
	lb/hr	22.1	17.0	31.8
	g/s	2.78	2.14	4.00
	tpy	96.7	74.5	139.1

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Estimated Cold Startup Emissions
Natural Gas Coal Emissions Combined
Table B-2a

Startup Operating Hour	SO2 (lb/hr)	NOx (lb/hr)	CO (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	Comments
Hour 1 (Phase I end of 1st hour)	0.7	23	18	1.2	2.3	Natural gas 100% of heat input
Hour 2 (Phase I end of 2nd hour)	1.3	47	35	2.3	4.7	Natural gas 100% of heat input
Hour 3 (Phase I end of 3rd hour)	2.0	70	53	3.5	7.0	Natural gas 100% of heat input
Hour 4 (Phase I end of 4th hour)	2.5	88	66	4.4	8.8	Natural gas 100% of heat input
Hour 5 (Phase I end of 5th hour)	2.5	88	66	4.4	8.8	Natural gas 100% of heat input
Hour 6 (Phase I end of 6th hour)	2.5	88	66	4.4	8.8	Natural gas 100% of heat input
Hour 7 (Phase I end of 7th hour)	2.5	88	66	4.4	8.8	Natural gas 100% of heat input
Hour 8 (Phase II end of 1st hour)	1124	263	248	16.1	22.2	Total heat input - 80% natural gas, 20% coal)
Hour 9 (Phase II end of 2nd hour)	1402	234	278	17.5	15.8	Total heat input - 60% natural gas, 40% coal)
Hour 10 (Phase II end of 3rd hour)	841	205	307	19.0	14.0	Total heat input - 40% natural gas, 60% coal)
Hour 11 (Phase II end of 4th hour)	560	175	336	20.5	10.8	Total heat input - 20% natural gas, 80% coal)
Hour 12 (Phase III end of 1st half hour)	210	117	222	17.5	8.2	Startup fuel oil goes to zero, coal goes to 100%
Hour 12 (Phase III end of 2nd half hour)	263	146	278	21.9	10.2	100% Coal

Startup Phase	SO2 (lbs)	NOx (lbs)	CO (lbs)	PM10 (lbs)	VOC (lbs)	Comments
Phase 1 Total Startup	14.0	490.9	368.2	24.5	49.1	summation of 7 hours (0 to 15% MCR)
Phase 2 Total Startup	3927	876.6	1168.8	73.1	62.8	summation of 4 hours (15 to 40% MCR)
Phase 3 Total Startup	236.7	131.5	249.8	19.7	9.2	summation of 1 hour (40 to 50% MCR)
TOTAL STARTUP EMISSIONS (lbs)	4,178	1,499	1,787	117	121	Total emissions for the 12-hour startup period.
EMISSIONS AT FULL LOAD (lb/hr):	526.0	292.2	321.4	43.8	11.7	CFB boiler emissions at 100% MCR
TOTAL EMISSIONS AT FULL LOAD FOR 12 HOURS (lbs):	6,312	3,506	3,857	526	140	CFB boiler emissions at 100% MCR times 12
STARTUP - FULL LOAD EMISSIONS DIFFERENTIAL (lb):	**-2,133**	**-2,007**	**-2,070**	**-409**	**-19.3**	**Negative value indicates that the total emissions during startup is below the full load emissions over a 12 hour period**

Indeck Elwood Energy Center
Point Emissions From Material Handling Operations
Table B-3

Predicted Dust Emission Rates for Coal and Limestone Handling System

(Refer to Fuel and Limestone Process Flow Diagram DWG. 104211-1-50-101)

Tag No.	Location	Dust Control Technology	Capacity (cfm)	Dust loads (gr/cfm)	Dust Collector Eff. (%)	Dust emission (gr/acfm)	Emission Rate (lbs/hr)	Emission Rate (Tons/yr)
F-001	Railcar Unloading	Fabric Filter	40000	10	99.99	0.001	0.343	1.50
F-101	Limestone reclaim	Fabric Filter	2000	10	99.95	0.005	0.086	0.38
F-102	Transfer house	Fabric Filter	5000	10	99.99	0.001	0.043	0.19
F-103	Crusher building	Fabric Filter	18000	10	99.99	0.001	0.154	0.68
F-104	Unit #1 Tripper Floor	Fabric Filter	10000	10	99.99	0.001	0.086	0.38
F-105	Unit #2 Tripper Floor	Fabric Filter	10000	10	99.99	0.001	0.086	0.38
	Total						0.454	1.99

Predicted Dust Emission Rates for Limestone Preparation System

(Refer to Limestone Preparation System Process Flow Diagram 104211-1-50-102)

Tag No.	Location	Dust Control Technology	Capacity (cfm)	Dust loads (gr/cfm)	Dust Collector Eff. (%)	Dust emission (gr/scfm)	Emission Rate (lbs/hr)	Emission Rate (Tons/yr)
F-301	Limestone In feed Silo Dust Collector	Fabric Filter	2500	10	99.95	0.005	0.107	0.47
F-303-T1	Limestone	Fabric Filter	28000	10	99.99	0.001	0.240	1.05
F-303-T3	Dryer/mill Dust		28000	10	99.99	0.001	0.240	1.05
F-303-T2	Collectors		28000	10	99.99	0.001	0.240	1.05
F-302-T1	Limestone	Fabric Filter	10500	10	99.99	0.001	0.090	0.39
F-302-T3	Preparation		10500	10	99.99	0.001	0.090	0.39
F-302-T2	Dust Collectors		10500	10	99.99	0.001	0.090	0.39
F-201-T1	Unit #1 Day Silo	Bin Vent Filter	6000	10	99.95	0.005	0.257	1.13
F-201-T2	Unit #2 Day Silo		6000	10	99.95	0.005	0.257	1.13
	Total						1.354	5.93

Predicted Dust Emission Rates for Fly and Bed Ash Handling System

(Refer to Fly/Bed Ash Handling System Process Flow Diagram 104211-1-50-103, 104)

Tag No.	Location	Dust Control Technology	Capacity (cfm)	Dust loads (gr/cfm)	Dust Collector Eff. (%)	Dust emission (gr/acfm)	Emission Rate (lbs/hr)	Emission Rate (Tons/yr)
F-202	Unit #1 Surge Hopper	Fabric Filter	300	10	99.95	0.005	0.013	0.06
F-203	Unit #2 Surge Hopper	Fabric Filter	300	10	99.95	0.005	0.013	0.06
F-204	Unit #1 Bed Ash Silo	Fabric Filter	9000	10	99.99	0.001	0.077	0.34
F-205	Unit #2 Bed Ash Silo	Fabric Filter	9000	10	99.99	0.001	0.077	0.34
F-206A	Blower Exhau. Stack	Fabric Filter	4500	10	99.99	0.001	0.039	0.17
F-206B	Blower Exhau. Stack	Fabric Filter	4500	10	99.99	0.001	0.039	0.17
F-207A	Blower Exhau. Stack	Fabric Filter	4500	10	99.99	0.001	0.039	0.17
F-207B	Blower Exhau. Stack	Fabric Filter	4500	10	99.99	0.001	0.039	0.17
F-208	Unit #1 Fly Ash Silo	Bin Vent Filter	7000	10	99.99	0.001	0.060	0.26
F-209	Unit #2 Fly Ash Silo	Bin Vent Filter	7000	10	99.99	0.001	0.060	0.26
	Bed Ash Loadout	Water Spray	-	-	-	-	-	-
	Fly Ash Loadout	Water Spray	-	-	-	-	-	-
	Total						0.454	1.99

Indeck Elwood Energy Center
Point Emissions From Material Handling Operations
Table B-3

Predicted values of CO, Nox, VOC for Limestone Drying Mills

(Refer to Limestone Preparation System Process Flow Diagram 104465-1-50-102)

Tag No.	Location	Capacity	Emission rate			Emission rate		
			CO	Nox	VOC	CO	Nox	VOC
		(MMbtu)	lb/MMbtu)	lb/MMbtu)	(lb/MMbtu)	(tons/yr)	(tons/yr)	(tons/yr)
HT-301-T1	Air Heater	12	0.2	0.073	0.02	10.51	3.85	1.05
HT-301-T1	Air Heater	12	0.2	0.073	0.02	10.51	3.85	1.05
HT-301-T1	Air Heater	12	0.2	0.073	0.02	10.51	3.85	1.05
	Total	36				31.5	11.5	3.2

Indeck El[illegible] Energy Center
Fugitive Emissions Fr[illegible]aterial handling Operations
Table B-4

Material Transfer Point Estimated Fugitive Dust Emissions

Source ID	Description	Moisture Content (%)	Wind Speed (mph)	Material Transferred (tpy)	TSP Multiplier	PM_{10} Multiplier	TSP EF (lb/ton)	PM_{10} EF (lb/ton)	Control Efficiency	Transfer Points	TSP Emissions (tpy)	PM_{10} Emissions (tpy)
F-210	Bed Ash Loadout	25	10.3	300,020	0.74	0.35	1.76E-04	8.35E-05	0%	1	2.65E-02	1.25E-02
F-211	Fly Ash Loadout	25	10.3	540,037	0.74	0.35	1.76E-04	8.35E-05	0%	1	4.77E-02	2.25E-02
F-002	Live Storage Coal Handling	10	1.3	2,194,130	0.74	0.35	4.32E-05	2.04E-05	99.9%	6	2.84E-04	1.34E-04
F-002	Live Storage Limestone Handling	0.7	1.3	560,640	0.74	0.35	1.79E-03	8.45E-04	99.9%	6	3.01E-03	1.42E-03
F-003	Dead Storage Coal Handling	10	1.3	2,194,130	0.74	0.35	4.32E-05	2.04E-05	95%	2	4.74E-03	2.24E-03

NOTES:
- Moisture content of limestone from AP-42, Section 13.2.4, Table 13.2.4-1 for crushed limestone.
- Moisture content of coal from analysis of typical "as received" coal for the Project.
- Moisture content of bed and fly ash based upon mixed moisture content specification of 25%.
- Wind speed within railcar unloading, live storage, end dead storage enclosures assumed to be equal to the lowest applicable range of AP-42, Section 13.2.4, Equation 1.
- Windspeed for bed and fly ash loadout based upon average annual windspeed for Chicago.
- Coal throughput based upon maximum annual coal throughput to the two CFB boilers.
- Limestone throughput based upon maximum consumption rate of 64 tons per hour and 8,760 hours per year.
- Bed ash throughput based upon maximum coal throughput with an average ash content of 10%, the limestone throughput, and 38.5% of the total ash being bed ash
- Fly ash throughput based upon maximum coal throughput with an average ash content of 10%, the limestone throughput, and 61.5% of the total ash being fly ash
- Control efficiency for railcar unloading, live storage, and dead storage represents combined controls achieved by the wetting systems and enclosures.
- TSP and PM10 emissions estimated from AP-42, Section 13.2.4, equation 1.

Bulldozing Emissions

Source ID	Description	Silt Content (%)	Moisture Content (%)	Operating Hours	Uncon. TSP (lb/hr)	Uncon. PM_{10} (lb/hr)	Control Efficiency	TSP Emissions (tpy)	PM_{10} Emissions (tpy)
F-002	Live Coal Pile Dozer	2.20	10.00	4,992	10.12	1.81	99.9%	0.03	0.00
F-002	Live Limestone Pile Dozer	1.60	0.70	4,992	219.10	46.52	99.9%	0.55	0.12
F-003	Dead Coal Pile Dozer	2.20	10.00	2,496	10.12	1.81	95%	0.63	0.11

NOTES:
- Moisture and silt contents of limestone from AP-42, Section 13.2.4, Table 13.2.4-1 for crushed limestone.
- Moisture content of coal from analysis of typical "as received" coal for the Project.
- Silt content of coal from AP-42, Section 13.2.4, Table 13.2.4-1 for coal as received at a coal fired power plant.
- Live storage operating hours based upon 8 hr/day for 365 days/yr.
- Dead storage operating hours based upon 8 hr/day, 2 days/wk, and 52 wks/yr.
- Control efficiency for live storage and dead storage represents combined controls achieved by the wetting systems and enclosures.
- TSP and PM10 emissions estimated from AP-42, Section 11.9, Table 11.9-1, equation for bulldozing.

Summary Of Fugitive Source Emissions

Source ID	Description	TSP Emissions (lb/hr)	TSP Emissions (tpy)	PM_{10} Emissions (lb/hr)	PM_{10} Emissions (tpy)
F-002	Live Storage Building	2.30E-01	5.75E-01	4.87E-02	1.22E-01
F-003	Dead Storage Building	5.07E-01	6.36E-01	9.11E-02	1.15E-01
F-210	Bed Ash Loadout	6.04E-03	2.65E-02	2.86E-03	1.25E-02
F-211	Fly Ash Loadout	1.09E-02	4.77E-02	5.15E-03	2.25E-02
	TOTALS	0.8	1.3	0.1	0.3

Indeck Elwood Energy Center
Emissions From Paved Roadways
Table B-5

Description	Silt Loading (g/m^2)	Avg. Vehicle Weight (tons)	Trips Per Year	Trip Distance (mi)	VMT	TSP Multiplier	PM_{10} Multiplier	TSP EF (lb/VMT)	PM_{10} EF (lb/VMT)	Control Efficiency	TSP Emissions (tpy)	PM_{10} Emissions (tpy)
Fly & bed ash disposal (loaded)	2	40	0	0.16	0	0.082	0.016	4.0	0.8	90%	0.0	0.0
Fly & bed ash disposal (unloaded)	2	20	0	0.38	0	0.082	0.016	1.4	0.3	90%	0.0	0.0
Limestone Delivery (loaded)	2	40	28,032	0.26	7,288	0.082	0.016	4.0	0.8	90%	1.5	0.3
Limestone Delivery (unloaded)	2	20	28,032	0.55	15,418	0.082	0.016	1.4	0.3	90%	1.1	0.2
Supplemental Fuel Delivery (loaded)	2	40	0	0.95	0	0.082	0.016	4.0	0.8	90%	0.0	0.0
Supplemental Fuel Delivery (unloaded)	2	20	0	1.26	0	0.082	0.016	1.4	0.3	90%	0.0	0.0
Miscellaneous	2	20	18,250	0.54	9,855	0.082	0.016	1.4	0.3	90%	0.7	0.1
TOTALS											**3.2**	**0.6**

NOTES:
Silt Loading based upon mean silt content for Sand and Gravel Processing facilities in AP-42, Section 13.2.1, Table 13.2.1-3.
Vehicle weights based upon estimated truck hauling capacities.
Trips per year based upon maximum material consumption rates (see Table B-4) and truck net hauling capacity.
Miscellaneous truck trips per year based upon 50 trips per day for 365 days/yr.
Trip distance based upon on site paved road haul route distance.
Control efficiency based upon estimated effectiveness of road wetting and sweeping operations.
TSP and PM10 emissions estimated from AP-42, Section 13.2.1, equation 1.

Indeck-Elwood Energy Center
Cooling Tower Emissions
Table B-6

DATA INPUTS

Total Circulation Rate,	127,950	gal/min	
Circulation rate, per cell	10662.5	gal/min-cell	
Drift efficiency	0.0005%		
Total Dissolved Solids	3000	ppmw	
Total Suspended Solids		ppmw	
Number of cells per tower	12	cells/tower	
Number of towers per plant	2	towers/plant	
Calculation of PM emissions per cell	0.080	lb/hr-cell	
	0.0101	g/s-cell	
Calculation of PM PTE	8.41	tpy	
Ambient Temp	49	°F	
Exhaust Flow Rate	1,296,900	ACFM	
Exhaust Temperature	76.437	°F	297.8 K
Cell Diameter	26.00	ft	530.9292
Exit Velocity	40.71	fps	ft2
	12.41	m/s	

Indeck Elwood Energy Center
Emissions From Miscellaneous Combustion Sources
Table B-7

FIRE PUMP DIESEL ENGINE
1.60 MMBtu/hr diesel engine input

CRITERIA	POLLUTANT					
	NOx	CO	SO2	PM-10	NMTOC	HCOH
lb/MMBtu	**3.22**	**0.21**	**0.051**	**0.03**	**0.02**	**1.18E-03**
lb/hr	5.15	0.34	0.08	0.04	0.03	0.002
hr/yr	500	500	500	500	500	500
tpy	**1.29**	**0.09**	**0.02**	**0.01**	**0.01**	**0.00047**

Note: AP-42 emission factors for diesel engines <600 hp Section 3.3 (10/96)
* NMTOC = non-methane total organic carbon

BOILER COOL DOWN PUMP DIESEL ENGINE
1.60 MMBtu/hr diesel engine input

CRITERIA	POLLUTANT					
	NOx	CO	SO2	PM-10	NMTOC	HCOH
lb/MMBtu	**3.22**	**0.21**	**0.051**	**0.03**	**0.02**	**1.18E-03**
lb/hr	5.15	0.34	0.08	0.04	0.03	0.002
hr/yr	500	500	500	500	500	500
tpy	**1.29**	**0.09**	**0.02**	**0.01**	**0.01**	**0.00047**

Note: AP-42 emission factors for diesel engines <600 hp Section 3.3 (10/96)
* NMTOC = non-methane total organic carbon

AUXILIARY BOILER
99.00 MMBtu/hr

CRITERIA	GAS FIRING POLLUTANT EMISSIONS					
	NOx	CO	SO2	PM-10	NMTOC	HCOH
lb/MMBtu	**0.08**	**0.10**	**0.0057**	**0.010**	**0.020**	**7.50E-05**
lb/hr	7.92	9.90	0.57	0.99	1.98	0.007
hr/yr	2500	2500	2500	2500	2500	2500
tpy	**9.90**	**12.38**	**0.71**	**1.24**	**2.48**	**0.00928**

Indeck Elwood Energy Center
Estimated Potential HAP Emissions
Table B-8

HAP	Boiler PTE (tpy)	Aux. Boiler and Drying Mills Gas Firing Emission Factors (lb/MMBtu)	Aux. Boiler Distillate Oil Firing Emission Factors (lb/MMBtu)	Auxiliary Boiler Maximum Emission rate (lb/hr)	Limestone Drying Mills Maximum Emission rate (lb/hr)	Diesel Engine Emission Factor (lb/MMBtu)	Boiler Cool Down Pump Engine Maximum Emission Rate (lb/hr)	Fire Pump Engine Maximum Emission Rate (lb/hr)	Facility-Wide PTE (tpy)
Antimony	7.57E-03								0.02
Arsenic	8.95E-02	2.00E-07	4.00E-06	3.96E-04	7.20E-06				0.18
Beryllium	1.95E-03	1.20E-08	3.00E-06	2.97E-04	4.32E-07				0.004
Cadmium	6.14E-01	1.10E-06	3.00E-06	2.97E-04	3.96E-05				1.23
Chromium	2.69E-01	1.40E-06	3.00E-06	2.97E-04	5.04E-05				0.54
Cobalt	1.65E-02	8.40E-08		8.32E-06	3.02E-06				0.03
Lead	1.53E-01		9.00E-06	8.91E-04					0.31
Manganese	3.58E-01	3.80E-07	6.00E-06	5.94E-04	1.37E-05				0.72
Mercury	5.12E-02	2.60E-07	3.00E-06	2.97E-04	9.36E-06				0.10
Nickel	3.01E-01	2.10E-06	3.00E-06	2.97E-04	7.56E-05				0.60
Selenium	3.87E-02	2.40E-08	1.50E-05	1.49E-03	8.64E-07				0.08
1,3-Butadiene						3.91E-05	6.26E-05	6.26E-05	0.00003
Acetaldehyde	3.13E-01					7.67E-04	1.23E-03	1.23E-03	0.63
Acetophenone	8.23E-03								0.02
Acrolein	1.59E-01					9.25E-05	1.48E-04	1.48E-04	0.32
Benzene	7.13E-01	2.10E-06	1.59E-06	2.08E-04	7.56E-05	9.33E-04	1.49E-03	1.49E-03	1.43
Benzyl Chloride	3.84E-01								0.77
Bis(2-ethylhexyl)phthalate	4.00E-02								0.08
Bromoform	2.14E-02								0.04
Carbon disulfide	7.13E-02								0.14
2-Chloroacetophenone	3.84E-03								0.008
Chlorobenzene	1.21E-02								0.02
Chloroform	3.24E-02								0.06
Cumene	2.91E-03								0.006
Cyanide	1.37E+00								2.74
2,4-Dinitrotoluene	1.54E-04								0.0003
Dimethyl Sulfate	2.63E-02								0.05
Dioxins	1.10E-04								0.0002
Ethylbenzene	5.16E-02		4.71E-07	4.66E-05					0.10
Ethyl Chloride	2.30E-02								0.05
Ethylene Dichloride	2.19E-02								0.04
Ethylene Dibromide	6.58E-04								0.001
Formaldehyde	1.32E-01	7.50E-05	7.50E-05	7.43E-03	2.70E-03	1.18E-03	1.89E-03	1.89E-03	0.29
Hexane	3.68E-02	1.80E-03		1.78E-01	6.48E-02				0.58
Hydrogen Chloride	4.94E+02								987.4

Indeck Elwood Energy Center
Estimated Potential HAP Emissions
Table B-8

HAP	Boiler PTE (tpy)	Aux. Boiler and Drying Mills Gas Firing Emission Factors (lb/MMBtu)	Aux. Boiler Distillate Oil Firing Emission Factors (lb/MMBtu)	Auxiliary Boiler Maximum Emission rate (lb/hr)	Limestone Drying Mills Maximum Emission rate (lb/hr)	Diesel Engine Emission Factor (lb/MMBtu)	Boiler Cool Down Pump Engine Maximum Emission Rate (lb/hr)	Fire Pump Engine Maximum Emission Rate (lb/hr)	Facility-Wide PTE (tpy)
Hydrogen Fluoride	2.51E+01								50.2
Isophorone	3.18E-01								0.64
Methyl Bromide	8.78E-02								0.18
Methyl Chloride	2.91E-01								0.58
Methylene Chloride	1.59E-01								0.32
Methyl Ethyl Ketone	2.14E-01								0.43
Methyl Hydrazine	9.33E-02								0.19
Methyl Methacrylate	1.10E-02								0.02
Methyl Tert Butyl Ether	1.92E-02								0.04
PAH	1.58E-02		8.81E-06	8.73E-04		1.68E-04	2.69E-04	2.69E-04	0.03
Phenol	8.78E-03								0.02
Propionaldehyde	2.08E-01								0.42
Propylene						2.58E-03	4.13E-03	4.13E-03	0.0021
Toluene	1.32E-01	3.40E-06	4.59E-05	4.55E-03	1.22E-04	4.09E-04	6.54E-04	6.54E-04	0.27
Tetrachloroethylene	2.36E-02								0.05
1,1,1-Trichloroethane	1.10E-02		1.75E-06	1.73E-04					0.02
Styrene	1.37E-02								0.03
Vinyl Acetate	4.17E-03								0.008
Xylenes	2.03E-02		8.07E-07	7.99E-05		2.85E-04	4.56E-04	4.56E-04	0.04
TOTALS									**1,048.2**

emissions rev3
All-HAPs
8/8/2002 7:12 AM

Indeck Elwood Energy Center
Estimated Potential HAP Emissions - CFB Boilers
Table B-8A

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Source	Emissions (lb/hr)	Emissions (tpy)
Antimony	5.91E-07	EPA HAP Study	1.73E-03	7.57E-03
Arsenic	7.00E-06	EPA HAP Study	2.04E-02	8.95E-02
Beryllium	1.52E-07	EPA HAP Study	4.45E-04	1.95E-03
Cadmium	4.80E-05	EPA HAP Study	1.40E-01	6.14E-01
Chromium	2.11E-05	EPA HAP Study	6.15E-02	2.69E-01
Cobalt	1.29E-06	EPA HAP Study	3.76E-03	1.65E-02
Lead	1.20E-05	EPA HAP Study	3.50E-02	1.53E-01
Manganese	2.80E-05	EPA HAP Study	8.17E-02	3.58E-01
Mercury	4.00E-06	MACT	1.17E-02	5.12E-02
Nickel	2.35E-05	EPA HAP Study	6.88E-02	3.01E-01
Selenium	3.02E-06	EPA HAP Study	8.84E-03	3.87E-02
Hydrogen Chloride	3.86E-02	EPA HAP Study	1.13E+02	4.94E+02
Hydrogen Fluoride	1.96E-03	EPA HAP Study	5.73E+00	2.51E+01
Dioxins	8.61E-09	AP-42	2.52E-05	1.10E-04
Acetaldehyde	2.44E-05	AP-42	7.14E-02	3.13E-01
Acetophenone	6.43E-07	AP-42	1.88E-03	8.23E-03
Acrolein	1.24E-05	AP-42	3.63E-02	1.59E-01
Benzene	5.57E-05	AP-42	1.63E-01	7.13E-01
Benzyl Chloride	3.00E-05	AP-42	8.77E-02	3.84E-01
Bis(2-ethylhexyl)phthalate	3.13E-06	AP-42	9.14E-03	4.00E-02
Bromoform	1.67E-06	AP-42	4.88E-03	2.14E-02
Carbon disulfide	5.57E-06	AP-42	1.63E-02	7.13E-02
2-Chloroacetophenone	3.00E-07	AP-42	8.77E-04	3.84E-03
Chlorobenzene	9.43E-07	AP-42	2.76E-03	1.21E-02
Chloroform	2.53E-06	AP-42	7.39E-03	3.24E-02
Cumene	2.27E-07	AP-42	6.64E-04	2.91E-03
Cyanide	1.07E-04	AP-42	3.13E-01	1.37E+00
2,4-Dinitrotoluene	1.20E-08	AP-42	3.51E-05	1.54E-04
Dimethyl Sulfate	2.06E-06	AP-42	6.01E-03	2.63E-02
Ethyl benzene	4.03E-06	AP-42	1.18E-02	5.16E-02
Ethyl Chloride	1.80E-06	AP-42	5.26E-03	2.30E-02
Ethylene Dichloride	1.71E-06	AP-42	5.01E-03	2.19E-02
Ethylene Dibromide	5.14E-08	AP-42	1.50E-04	6.58E-04
Formaldehyde	1.03E-05	AP-42	3.01E-02	1.32E-01
Hexane	2.87E-06	AP-42	8.39E-03	3.68E-02
Isophorone	2.49E-05	AP-42	7.26E-02	3.18E-01
Methyl Bromide	6.86E-06	AP-42	2.00E-02	8.78E-02
Methyl Chloride	2.27E-05	AP-42	6.64E-02	2.91E-01
Methyl ethyl ketone	1.67E-05	AP-42	4.88E-02	2.14E-01
Methyl hydrazine	7.29E-06	AP-42	2.13E-02	9.33E-02
Methyl Methacrylate	8.57E-07	AP-42	2.50E-03	1.10E-02
Methyl tert butyl ether	1.50E-06	AP-42	4.38E-03	1.92E-02
Methylene Chloride	1.24E-05	AP-42	3.63E-02	1.59E-01
PAH	1.23E-06	AP-42	3.60E-03	1.58E-02
Phenol	6.86E-07	AP-42	2.00E-03	8.78E-03
Propionaldehyde	1.63E-05	AP-42	4.76E-02	2.08E-01
Tetrachloroethylene	1.84E-06	AP-42	5.39E-03	2.36E-02
Toluene	1.03E-05	AP-42	3.01E-02	1.32E-01
1,1,1-Trichloroethane	8.57E-07	AP-42	2.50E-03	1.10E-02
Styrene	1.07E-06	AP-42	3.13E-03	1.37E-02
Xylenes	1.59E-06	AP-42	4.63E-03	2.03E-02
Vinyl Acetate	3.26E-07	AP-42	9.52E-04	4.17E-03

Indeck Elwood Energy Center
EPA Emission Modification Factors For Metallic HAP Emissions
Table B-8B

HAP	Coal Conc. (ppmw)	Uncontrolled (lb/MMBtu)	Boiler Configuration EMF	FF EMF	Combined EMF	Control Efficiency	Controlled (lb/MMBtu)
Antimony	2.3	1.97E-04	1.00	0.003	0.0030	99.70%	5.91E-07
Arsenic	53.0	4.54E-03	0.77	0.002	0.0015	99.85%	7.00E-06
Beryllium	3.2	2.72E-04	0.56	0.001	0.0006	99.94%	1.52E-07
Cadmium	14.0	1.20E-03	1.00	0.04	0.0400	96.00%	4.80E-05
Chromium	26.7	2.29E-03	0.46	0.02	0.0092	99.08%	2.11E-05
Cobalt	15.0	1.29E-03	1.00	0.001	0.0010	99.90%	1.29E-06
Lead	111	9.51E-03	0.42	0.003	0.0013	99.87%	1.20E-05
Manganese	259	2.22E-02	0.63	0.002	0.0013	99.87%	2.80E-05
Nickel	41.0	3.51E-03	0.67	0.01	0.0067	99.33%	2.35E-05
Selenium	4.2	3.60E-04	0.84	0.01	0.0084	99.16%	3.02E-06
Hydrogen Chloride	2500	2.14E-01	1.00	0.18	0.18	82.00%	3.86E-02
Hydrogen Fluoride	127	1.09E-02	1.00	0.18	0.18	82.00%	1.96E-03
NOTES:	Coal concentrations are the maximum values found in all US coals as reported in EPA Utility HAP Study.						
	Control efficiencies determined from Emission Modification Factors (EMF) from the EPA Utility HAP Study.						
	Boiler configuration for the new unit is based upon CFB.						
	PM control for new unit reflected in SO2 control EMF which is for a SDA/FF combination.						

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF LEGAL COUNSEL
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TELEPHONE (217) 782-5544 FACSIMILE (217) 782-9807

DATE: March 29, 2006

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September 30, 2003

David Kolaz
Chief
Bureau of Air
Illinois Environmental Protection Agency
1021 N. Grand Ave. East
Springfield, IL 62702

Re: Indeck-Elwood Energy Center air permit authorization for construction of a 600 MW coal-fired power plant in Will County.
IDNR Project Code: 0400546

Dear Mr. Kolaz:

This project is in the vicinity of the Joliet Army Ammunition Plant Illinois Natural Area, also known as the Midewin National Tallgrass Prairie Grassland. This Natural Area supports numerous State and Federal listed plant and animal species. The Northern Harrier (*Circus cyaneus*), Henslow's Sparrow (*Ammodramus henslowii*), and Leafy Prairie Clover (*Dalea foliosa*) are listed as endangered in Illinois. The Federal government also lists the Leafy Prairie Clover as endangered.

The proposed power plant's high potential for emissions of VOM, NO_X, SO_2, PM_{10}, CO, and hydrogen chloride upwind of the Midewin, in association with the species located there, are of concern to the Department. The potential source of acidic, or precursors of acidic deposition are a potential direct threat to sensitive habitat areas in the Midewin. The direct, indirect, and cumulative effects from construction and operation of the power plant may undermine the Midewin Land and Resource Management Plan objectives for ecosystem restoration and outdoor recreation.

Restoration sites in the vicinity of the proposed power plant have sensitive flora that require high-quality soil and water conditions. These natural resources may be directly impacted by a change in environmental conditions that include pH, base cation availability and exchange capacity in soils, micronutrient availability in soils, and existence of toxic metals. Indeck-Elwood's proposed emissions of hydrogen chloride, NO_X, and SO_2 emissions would appear to be acidic or precursors for acid deposition and could cause direct effects to sensitive habitat types at the Midewin by decreasing the pH of soil and water as a result of acid deposition downwind of the power plant.

The Department has also reviewed a September 4, 2003, IEPA memo, to Chris Romaine from Scott Leopold, regarding the zone of significant impact for this project. It is our understanding that significant impact levels are thresholds that trigger the need for a detailed modeling study, and do not necessarily correlate with an action threshold for flora or fauna. Although the predicted impacts from this facility do not violate PSD increments or exceed sensitive vegetation screening levels, the Department is concerned that the Midewin, and the protected species it supports, may be adversely impacted. Additionally, it appears that the zone of significant impact was limited to emissions from the boiler stacks, and that not all potential sources of adverse impact within the project footprint were considered. Of particular concern is the particulate matter that may result from the receipt and handling of coal used to fuel this facility.

Title 17 Administrative Code Part 1075.40 requires that a Detailed Action Report be submitted to the Department, due to the potential for adverse impacts to protected natural resources. IEPA must provide sufficient information and analysis to determine the potential indirect, direct, and cumulative adverse impacts, of this project, on each of the protected resources identified at the beginning of this letter. The Department will render a biological opinion within 60 calendar days of receipt of a completed Detailed Action Report. In accordance with 17 IL Adm. Code Part 1075, "the proposed action shall not commence until the completion of the consultation process."

In addition, please be advised that this letter does not satisfy the statutory requirement of any other State agency to engage in consultation with the Department if they authorize, fund, or perform any activity which may alter environmental conditions. Nor does this letter constitute compliance with the Interagency Wetland Policy Act if a State Agency funds any activity related to this project.

Please do not hesitate to contact me or Mike Branham of my staff at (217) 785-5500 if you should have any questions, or would like to set up a meeting to discuss this matter in more detail.

Sincerely,

Stephen K. Davis, P.G.
Chief
Division of Resource Review and Coordination
Office of Realty and Environmental Planning

cc: Division File
Gina Roccaforte, IEPA
Chris Romaine, IEPA
Leslie Sgro, IDNR
Tom Flattery, IDNR
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Joel Brunsvold, Director

October 10, 2003

VIA FACSIMILE AND HAND DELIVERY

David J. Kolaz, Chief
Bureau of Air
Illinois Environmental Protection Agency
1021 N. Grand Avenue East
Springfield IL 62702

Re: Indeck-Elwood Energy Center Air Permit Authorization for Construction of a 600 MW Coal-Fired Power Plant in Will County
IDNR Project Code: 0400546

Dear Mr. Kolaz:

This letter addresses consultation pursuant to Title 17 Illinois Administrative Code1075.40 with regard to the proposed Air Quality Permit for Indeck-Elwood LLC.

Based on the Department's review of the Agency Action Report submitted for this action, the Department had previously notified the Agency that the proposed action is located in the vicinity of species of plants and animals listed as endangered or threatened under the Illinois Endangered Species Protection Act, and in the vicinity of areas listed on the Illinois Natural Areas Inventory under the Illinois Natural Areas Preservation Act.

On October 8, 2003, the Agency submitted the Detailed Action Report required by Part 1075.40. In addition to the Agency's description of the proposed action, the Detailed Action Report contained a number of attachments previously submitted by the Agency to the Department. The Detailed Action Report listed the protected species and Natural Areas in the vicinity of the proposed action. In performing its review, the Department has also supplemented the information contained in the Detailed Action Report with information the Department has historically collected on the areas in the vicinity of the proposed action.

After reviewing the information provided in the Detailed Action Report and the other historical information collected by the Department, it is the Biological Opinion of the Department that the proposed action may, in conjunction with other cumulative impacts, jeopardize one or more listed species, may adversely affect a listed species' essential habitat and may degrade or adversely modify

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the Natural Areas. It is the opinion of the Department that National Ambient Air Quality Standards adopted by the USEPA are generally designed to address impacts to human receptors. Direct application of these standards to all flora and fauna associated with the permit action may not be sufficient to address all potential endpoints at this site. In order to respond to such issues, the Department believes that prior to the facility coming on-line in approximately 2007, baseline conditions in the area should be quantified to determine if there is a need for appropriate avoidance, reduction or compensation measures. Therefore, the Department's recommendation to avoid or ameliorate any adverse effects of the proposed action is for the Agency to condition the issuance of the proposed Air Quality Permit on (1) the establishment of a monitoring and data-gathering program, (2) an evaluation of the existence and degree of potential adverse impacts to species and natural areas listed in Tab 14 of the Detailed Action Report, and (3) based upon the results of the foregoing program and evaluation, the establishment of appropriate avoidance, reduction or compensation measures. The Department further recommends the creation of an Interagency Team to develop data-gathering and monitoring strategies within the next twelve months. The data gathering and monitoring strategies should address both pre- and post-operation conditions.

Thank you for participating in the consultation process. Consultation may be terminated upon the scheduling of a meeting to discuss the Department's recommendations, and notification of the Agency's determination regarding these recommendations.

Sincerely,

Tom Flattery

Tom Flattery, Office Director
Office of Realty and Environmental Planning

TF:JF

Excerpts

Indeck-Elwood Energy Center

PSD Construction Permit Application (Volume I)

Elwood, IL

Revised August 2002 (rev 1)

Prepared For:

Indeck – Elwood, LLC
600 North Buffalo Grove Road
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Prepared By:

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5. CONTROL TECHNOLOGY ANALYSIS

5.1 Best Available Control Technology (BACT) Analysis

As previously discussed, a BACT analysis is required for PSD subject sources. BACT is defined in the PSD regulations as "an emissions limitation based on the maximum degree of reduction for each air pollutant subject to regulation which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs determines is achievable through application of production processes or available methods, systems and techniques for control of each air pollutant."

The EPA requires a "top-down" approach to the BACT analysis. The process begins with the identification of control technology alternatives for each pollutant. Technically infeasible technologies are eliminated and the remaining technologies are ranked by control efficiency. These remaining technologies are evaluated based on economic, energy and environmental impacts. If, an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected for the given pollutant.

BACT is expressed as an emission rate and may be achieved from one or the combination of the following: (1) change in the raw material processes; (2) a process modification; and (3) add-on controls. Each of these techniques for achieving BACT are evaluated below. In determining BACT, the Project evaluated EPA's recommended sources of information for determining BACT, specifically:

- Pre-construction permits for other similar sources recently issued; and
- Levels "demonstrated in practice" at other facilities as determined by other agencies, including review of the EPA's RACT/BACT/LAER Clearinghouse (RBLC).

The Project used a "top-down" approach to determine BACT in accordance with the procedures described above. A BACT analysis is presented below for nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), carbon monoxide (CO), volatile organic compounds (VOM), sulfuric acid mist, beryllium, mercury, and fluorides.

5.2 Evaluation of Emissions Limiting Techniques

5.2.1 Change in Raw Materials

A change in raw materials is typically considered for industrial processes that use chemicals such as solvents where substitution with a lower emitting chemical may be technically feasible. In this case, the "raw material" is a fuel to be combusted for the generation of electricity. The primary fuel to be combusted by the Project is Illinois bituminous coal. The Project may also fire supplemental fuel (petcoke and waste coal) blended with the Illinois bituminous coal. The emissions from the combustion of various types of coals are relatively similar for all pollutants with the exception of SO_2 emissions. The sulfur content of the coal will affect the SO_2 emissions from the boiler. However, the Project will utilize CFB technology to control SO_2 emissions to levels achieved by lower sulfur coals. The Project is committed to firing Illinois bituminous coal as the primary fuel to provide both an economic benefit for the facility as well as an economic benefit to the Illinois coal mining industry.

Since the same emission levels of all PSD regulated pollutants can be achieved through the application of BACT controls regardless of the type of fuel fired, a change from 100% firing Illinois bituminous coal will not impact the emission levels for the Project.

5.2.2 Process Modifications

Similar to changes in raw materials, process modifications are typically considered for industrial processes that use chemicals where a change in the process methods or conditions may result in lower emissions. In this case, the "process" is a combustor/boiler, and more specifically a CFB boiler. CFB boilers are recognized as an inherently low emission technology for NO_x as compared to conventional coal combustion. The CFB combustor can be considered equivalent to a low-NO_x burner (LNB) with separated overfire air (SOFA). Sub-stoichiometric primary air, and the use of a circulating bed reduces combustion temperatures as compared to conventional pulverized coal (PC) or spreader stoker combustors. The lower bed temperature minimizes NO_x formation. Additionally, the injection of limestone directly into the CFB provides a high level of SO_2 emissions control. Therefore, emissions of NO_x and SO_2 from CFB boilers are lower than those from conventional coal boilers. For this reason, the US Department of Energy (DOE) and the EPA consider CFB technology a Clean Coal Technology.

5.2.3 Add-on Controls

Coal fired boilers generally employ various types of add-on controls to reduce NO_x, SO_2, and PM/PM_{10} emissions. A review of add-on controls that have been applied to CFB boilers, indicates that that the following types of add-on controls have been applied to CFB boilers:

- NO_x - Selective Non-Catalytic Reduction (SNCR)
- SO_2 – Spray Dryer Adsorbers (SDA)
- PM/PM_{10} – Fabric Filters (Baghouses) & Electrostatic Precipitators (ESPs)

The Project is proposing to utilize SNCR and baghouses to control emissions of NO_x and PM/PM_{10} from the boilers. No add-on SO_2 controls are proposed, as the Project will control SO_2 emissions within the CFB boiler to levels achieved by other CFB projects with add-on SO_2 controls.

Add-on controls are discussed in further detail in the pollutant specific BACT sections.

5.3 Sources Consulted to Determine BACT

This section outlines the results of an evaluation to determine BACT.

5.3.1 Permitted Emission Limits

The RACT/BACT/LAER Clearinghouse (RBLC) database was searched for recently permitted CFB coal fired projects. Additionally, state agencies were contacted to identify emission limits for other known CFB boiler projects not contained in the RBCL. Table 5-1 provides a list of PSD permit limits for all known CFB boiler projects permitted since 1995. These emission limits were evaluated for each PSD subject pollutant to determine BACT for the Project.

Table 5-1: Summary of PSD Permitted CFB Boiler Projects Since 1995

Project Name	State	Permit Status	Size (MW)	Fuel	SO_2 Emission Limit (lb/MMBtu)	NOx Emission Limit (lb/MMBtu)	PM Emission Limit (lb/MMBtu)	CO Emission Limit (lb/MMBtu)	VOC Emission Limit (lb/MMBtu)	Control Technology
Northampton Generating	PA	Permit Issued 01/14/1995	110	Anthracite Culm	0.129 (24-hr)	0.10 (24-hr)	0.0088	0.15 (4-hr)	0.005	SNCR, FF, Limestone Inj.
York County Energy	PA	Permit Issued 07/25/1995	250	Bituminous Coal	0.25	0.125 (LAER)	0.011	NA	0.004	SNCR, FF, Limestone Inj.
Toledo Edison - Bayshore Plant	OH	Permit Issued 06/20/1997	175	Petcoke, Coal	0.60	0.20	0.03	0.13	NA	FF, Limestone Inj.
Archer Daniels Midland	IA	Permit Issued 06/30/1998	150	Coal	0.36 (30 day)	0.07 (30-day)	0.03	0.15 (3-hr)	0.0072	SNCR, FF, Limestone Inj.
Archer Daniels Midland	IL	Permit Issued 12/24/1998	150	Coal	0.70	0.12	0.025	0.10	0.032	SNCR, FF, Limestone Inj.
JEA Northside	FL	Permit Issued 7/14/99	2 x 300	Coal and Petcoke	0.15 (30-day) 0.20 (24-hr)	0.09 (30-day)	0.011 (3-hr)	0.127 (24-hr)	0.005 (3-hr)	SNCR, ESP or FF, Limestone Inj. + Polishing Scrubber
EnviroPower of Illinois, LLC	IL	Permit Issued July 3, 2001	2 x 250	Coal and Coal Refuse	0.25[1] (30-day)	0.125[2] (30-day)	0.015	0.27 (30-day)	0.007	SNCR, ESP, Limestone Inj. + Polishing Scrubber
Kentucky Mountain Power	KY	Permit Received May 4, 2001	2 x 250	Waste Coal and Bit. Coal	0.13 (30-day)	0.10[3] (30-day)	0.015	0.27 (30-day)	0.0072	SNCR, ESP, Limestone Inj. + Polishing Scrubber
Reliant Energy Seward	PA	Notice of Intent to Approve	2 x 260	Waste Coal and Bit. Coal	0.6 (30 day)	0.15 (30-day)	0.010			SNCR, FF, Limestone Inj.
Energy Services of Manitowoc	WI	Permit Received June 28, 2001	99	Petcoke	0.20 (annual) 0.22 (24-hr)	0.07[4] (24-hr)	0.011	0.11	0.0085	SNCR, ESP, Limestone Inj. + Polishing Scrubber

[1] Greater than 92% removal if = or > 0.20 lb/Mbtu.
[2] More stringent limits, but not less than 0.07 lb/MMBtu, may be set as a result of a NOx evaluation study after start-up.
[3] Contingent upon optimization study, goal of 0.07 lb/MMBtu
[4] Emissions above 0.07 lb/MMBtu are allowed at operating loads below 95% as long as mass emissions do not exceed 74 lb/hr.

5.3.2 SIP Limits

States typically have NO_x, SO_2, and PM/PM_{10} limits for combustion sources in their State Implementation Plans (SIPs). Several California air pollution control district regulations, including San Joaquin and Kern County, were reviewed since these areas contain several coal fired boilers and are ozone non-attainment areas, therefore, it would be expected that these areas would have the most stringent limits in their SIPs. The San Joaquin rules have a NO_x limit of 0.2 lb/MMBTU for solid fuel fired boilers. The Kern County NO_x rules exempt solid fuel fired boilers. Illinois regulations contain a NO_x RACT limit for CFB boilers of 0.3 lb/MMBTU. The proposed BACT limits for all PSD subject pollutants are less than the emission limits identified in any state SIP.

5.4 Determination of BACT for PSD Subject Pollutants

The Project evaluated the emissions limiting techniques discussed above to establish BACT for each PSD subject pollutant. The PSD subject pollutants for the Project are NO_x, SO_2, PM/PM_{10}, CO, VOM, sulfuric acid mist, beryllium, mercury, and fluorides. The BACT analysis for each of these pollutants is provided below.

5.4.1 Nitrogen Oxides (NO_x)

5.4.1.1 CFB Boilers

Nitrogen oxides (NO_x) are formed during the combustion of fuel and are generally classified as either thermal NO_x or fuel related NO_x. Thermal NO_x results when nitrogen in the combustion air is oxidized at high temperatures to yield NO, NO_2 and other oxides of nitrogen. Fuel related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. A coal fired CFB boiler produces both thermal NO_x as well as fuel related NO_x emissions.

The rate of formation of thermal NO_x is predominantly exponential with peak flame temperature and is also a function of residence time and free oxygen. Thermal NO_x emissions can be minimized by limiting peak combustion temperatures and excess air. However, limiting peak combustion temperatures and excess air can result in higher emissions of CO, VOMs, and PM/PM_{10}. Fuel related NO_x emissions are dependent upon the amount of fuel bound nitrogen in the fuel and cannot be restricted through boiler operating conditions.

CFB boilers are inherently low-NO_x emitting. CFB furnace temperatures are maintained at relatively low combustion temperatures, typically between 1,500-1,700°F, and the combustion air is fed to the boiler in stages. This combination of low furnace temperature and staged combustion air minimizes the formation of thermal NO_x and fuel NO_x. Although combustion temperatures are minimized, combustion efficiency is maintained at a very high level due to the extended residence time provided in the boiler due to the continuous recirculation of solids collected in the boiler's cyclone. Therefore, CFB boilers minimize the formation of NO_x emissions while also providing a high combustion efficiency to minimize CO, VOM, and PM/PM_{10} emissions.

The operating temperature of CFB boilers also provides the ideal environment for application of selective non-catalytic reduction (SNCR) technology to further reduce NO_x emissions. SNCR involves the injection of ammonia or urea into the boiler effluent gas at a specific temperature. Upon mixing with the effluent at the proper temperature, ammonia reacts with NO_x to produce nitrogen and water. The optimum operating temperature for the non-catalytic reaction of ammonia and NO_x is approximately 1,600°F, which is comparable to the operating temperature of CFB boilers.

A review of the most recently permitted CFB projects shows that all of these projects employ SNCR to control NO_x emissions. The permitted NO_x emission levels for these projects range from 0.07 to 0.125 lbs/MMBtu. The recently permitted Enviropower project in Illinois was permitted at an emission rate of 0.125 lbs/MMBtu with a post startup optimization program designed to reduce the permitted emission rate to no lower than 0.07 lbs/MMBtu.

The Project proposes a NO_x BACT emission rate of 0.10 lbs/MMBtu on a 30 day rolling average. This proposed NO_x BACT emission rate was determined based upon information provided by the boiler vendor. The NO_x BACT emission rate will be maintained at all operating loads above 50 percent. The Projects that have proposed optimization programs to establish NO_x BACT have not addressed the potential for higher NO_x emission levels at reduced operating loads. The recently issued Energy Services of Manitowoc permit in Wisconsin does not limit the short-term (lb/MMBtu) emission rate at operating loads less than 95 percent. The Energy Services of Manitowoc permit instead caps the NO_x emission rate in pounds per hour at reduced operating loads.

The Project believes that proposing a constant emission rate limit of 0.10 lbs/MMBtu across all expected operating loads is consistent with the most stringent PSD permitted emission levels.

Another NO_x emissions control technique which could be applied to the project is Selective Catalytic Reduction (SCR). SCR utilizes a catalyst to lower the temperature necessary to facilitate the reaction of ammonia and NO_x to form nitrogen and carbon dioxide. SCR is not proposed for the Project for several reasons, primarily that SCR has never been applied on a CFB boiler.

SCR has only been used on pulverized coal (PC) boilers. The NO_x emission levels achieved by SCR on new PC boilers are equal to or higher than the proposed BACT emission rate for the Project. The lowest NO_x emission rate identified for a new PC boiler equipped with SCR is 0.09 on an annual basis for three Wyoming projects permitted in 2001 (North American Power – Two Elk, North American Power – Mid PRB, and Black Hills Energy). The proposed emission level for the Project of 0.10 lbs/MMBtu on a 30-day rolling basis is equivalent to or lower than 0.09 lbs/MMBtu on an annual basis. Therefore, the combination of a CFB boiler with SNCR results in equal to or lower NO_x emissions than any other coal fired boiler project equipped with SCR.

All known SCR applications on PC boilers in the United States are "hot side" installations, meaning that the SCR system is placed prior to the air preheater upstream from the SO_2 and PM controls. Installing a "hot side" SCR on a CFB boiler would provide significant technical difficulties due to the high solids loading on the catalyst. The high fuel solids and limestone carryover would increase the fouling of the SCR catalyst as compared to a PC boiler application. The calcium carryover from excess limestone in the CFB may combine with SO_2/SO_3 to form calcium sulfate on the catalyst surface, rendering it ineffective. To account for the increased fouling of the catalyst, additional layers of catalyst would need to be installed thereby increasing the cost of the system. Additional maintenance would also be necessary due to the increased fouling. Due to these technical complications with SCR and the low NO_x emissions achieved by SNCR, no CFB boilers have installed SCR to control NO_x emissions.

In summary, no known CFB boiler has applied SCR to reduce NO_x emissions. Therefore, SCR has not been demonstrated in practice for a CFB boiler. Furthermore, the proposed NO_x BACT emission limit for the Project is equivalent to the lowest NO_x emission levels permitted for a coal fired boiler equipped with SCR.

5.4.1.2 Auxiliary Boiler

The project will include a natural gas fired auxiliary boiler with a maximum heat input of 99 MMBtu/hr. The boiler will be limited to 2,500 hours per year of operation. The boiler will be equipped with low-NO_x burners to limit NO_x emissions to 0.08 lb/MMBtu and meet BACT requirements.

In addition to the low-NO_x burners proposed for the boiler, add-on controls were also investigated as BACT for the boiler. Two types of add-on NO_x controls could be applied to the Project's boiler: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). An analysis of these two control technologies is provided below.

Selective Catalytic Reduction (SCR)

SCR is a process that involves post combustion removal of NO_x from flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts NO_x to nitrogen and water by the following general reactions:

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

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

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Three types of catalyst bed configurations have been successfully applied to commercial sources: the moving bed reactor, the parallel flow reactor, and the fixed bed reactor. The fixed bed reactor is applicable to sources with little or no particulate matter present in the flue gas, such as the exhaust gas for the proposed auxiliary boiler. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow within the auxiliary boiler and transport of the reactants to the active catalyst sites takes place through a combination of diffusion and convection.

Sulfur content of the fuel can be a concern for systems that employ SCR, however utilizing natural gas as the sole fuel should afford reasonable catalyst life. Catalyst systems promote partial oxidation of sulfur dioxide (from trace sulfur in gas and the mercaptans used as an odorant) to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. At the temperatures of the auxiliary boiler exhaust gases, SO_3 and sulfuric acid may react with excess ammonia to form ammonium salts. These ammonium salts may condense as the flue gases are cooled, or may be emitted from the stack as increased emissions of PM_{10}. Sulfates and nitrates emitted from the stack are also precursors to atmospheric formation of PM_{10}.

The SCR process may also be subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation is generally the result of either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalyst suppliers typically guarantee a 3-year lifetime for very low emission level, high performance catalyst systems.

The environmental impacts associated with the use of SCR include emissions of unreacted ammonia and increased PM/PM_{10} emissions. Ammonia is a $PM_{10}/PM_{2.5}$ precursor and ammonia salts ($PM_{10}/PM_{2.5}$) may be emitted from the stack.

Using EPA cost data for SCR on gas fired package boilers found in *Alternative Control Techniques Document – NO_x Emissions From Industrial/Commercial/Institutional Boilers* (EPA-453/R-94-022), the uninstalled SCR capital equipment cost for the proposed boiler would be approximately $273,000. This includes the catalyst, reactor, ammonia delivery and control system, and boiler modification to accommodate the SCR reactor. Using EPA cost factors; the total installed capital cost of an SCR system would be approximately $432,000. The annual costs, including the annualized cost of capital and operating costs, is in excess of $156,000.

Assuming 90 percent removal, the annual reduction in NO_x emissions would be approximately 8.9 tons resulting in a control cost of greater than $17,000 per ton of NO_x. This is not cost effective for NO_x control. Therefore, SCR was eliminated as economically infeasible as BACT for the gas fired auxiliary boiler. Table 5-2 presents the SCR cost analysis for the auxiliary boiler.

Selective Non Catalytic Reduction (SNCR)

Also referred to as "thermal" non-catalytic reduction, SNCR relies on injecting ammonia or urea compounds into the exhaust gas at a temperature range of 1,600 to 2,000°F. At this temperature, NO_x and NH_3 react without a catalyst, reducing NO_x to water and nitrogen. Since there is no catalyst, the conversion of NO_x to water and nitrogen is dependent upon the residence time within the optimum reaction temperature window. Adequate mixing of the reducing agent with the exhaust gas is another key to success.

Table 5-2: SCR Control Costs – Auxiliary Boiler

Control System Life:	**10**	**years**	**Operating Hours per Year (52 weeks):**	**2,500**
Interest Rate:	**8%**		**Uncontrolled Emissions (tpy)**	**9.9**
Vendor:	**EPA Guidance**		**Control Efficiency (%)**	**90%**
Capital Recovery Factor (CRF)	**0.149**			

Equipment Cost (EC)	(Factor)		Capital Recovery (0.14903 x [TCI - Cat. Replace/0.388])	$33,792
a. SCR, Housing & ducting ($2,400/MMBtu)		$237,600	Direct Operating Costs	
b. Instrumentation (0.10A)		$23,760	a. Ammonia	$1,185
c. Taxes and Freight	(EC*0.05)	$11,880	b. Electricity	NA
			c. Operating Labor (OL):(1.0 hr/shift)($25.6/hr)	$8,000
Total Equipment Cost (TEC)		$273,240	d. Maintenance Labor (OL):(0.5 hr/shift)($25.6/hr)	$4,000
Direct Installation Costs			e. Maintenance Materials (MM): (MM=ML)	$4,000
			f. Supervisor (15% of Operator)	$1,200
a. Foundation	(TEC*0.08)	$21,859	g. Catalyst Replacement (3 yrs @ 8% interest)	$79,513
b. Erection and Handling	(TEC*0.14)	$38,254	h. Annual Catalyst Disposal Cost ($15/CF * 0.2638)	NA
c. Electrical	(TEC*0.04)	$10,930	i. Performance Loss (0.5%, $0.06/kwh)	NA
d. Piping	(TEC*0.02)	$5,465	j. Production Loss (10% of Perf. Loss)	NA
e. Insulation	(TEC*0.01)	$2,732	k. Dilution Steam (6$/1,000 lb)	$795
f. Painting	(TEC*0.01)	$2,732		
			Total Direct Operating Cost	$97,898
Total Direct Installation Cost		$81,972	Indirect Operating Costs	
			a. Overhead (60% of OL+ML+MM)	$7,200
Indirect Installation Costs			b. Property Tax: (TCC*0.01)	$4,317
a. Engineering and Supervision	(TEC*0.1)	$27,324	c. Insurance: (TCC*0.01)	$4,317
b. Construction/Field Expenses	(TEC*0.05)	$13,662	d. Administration: (TCC*0.02)	$8,634
c. Construction Fee	(TEC*0.1)	$27,324		
d. Start up	(TEC*0.02)	$5,465	**Total Indirect Operating Cost**	$24,468
e. Performance Test	(TEC*0.01)	$2,732		
			Total Annual Cost	**$156,158**
Total Indirect Installation Cost		$76,507		
			NOx Reduction (tons/yr)	**8.9**
Total Capital Cost (TCC)		$431,719		
			Cost of Control ($/ton - NOx)	**$17,526**

Gas fired package auxiliary boilers of the type proposed generally have a temperature profile in which the temperature drops from approximately 2400°F to 500°F over a very short distance. Because of this compact design, which is typical of package boilers, the exhaust gas does not maintain suitable temperatures for a sufficient duration to allow for reaction of NO_x with NH_3. Given the short residence time at the optimum SNCR reaction temperature within the boiler and the low uncontrolled emission rate (0.08 lb/MMBtu), the efficiency of an SNCR system will be minimal.

SNCR operating experience exists on larger utility boilers but not on smaller package boilers. SNCR is not considered to be technically feasible for small boilers due to the lack of demonstrated experience and the inadequate residence time at the required reaction temperature. SNCR is therefore not considered to be BACT.

Combustion Controls

The firing of natural gas as the sole fuel, application of low-NO_x burners, and limiting operating hours to 2,500 hr/yr is the proposed NO_x BACT for the auxiliary boiler. A review of the RBLC database did not identify any recent auxiliary boiler installations. The proposed gas fired auxiliary boiler equipped with low-NO_x burners will limit NO_x emissions to 0.08 lb/MMBtu.

5.4.1.3 Limestone Drying Mills

The Project will include three natural gas fired limestone drying mills, each with a maximum heat input of 12 MMBtu/hr. The limestone drying mills will have NO_x emissions no greater than 0.073 lb/MMBtu. Given the small capacity of these sources and the low uncontrolled emission rate, the installation of add-on NO_x controls such as SCR, would not be cost effective. The firing of natural gas as the sole fuel represents BACT for the limestone drying mills.

5.4.1.4 Emergency Diesel Engines

EPA's Alternative Control Technology (ACT) document for reciprocating engines (EPA, 1996) lists available back end techniques such as SCR as well as combustion control techniques such as ignition retard for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for "emergency diesel engines that operate less than 500 hours/year". The Project proposes to limit operation of the fire pump and boiler cooling water pump engines to less than 500 hours per year. Therefore, BACT for these engines is limiting operating hours to less than 500 per year.

5.4.2 Sulfur Dioxide (SO_2)

5.4.2.1 CFB Boilers

SO_2 emissions result from oxidation of sulfur found in the fuel, in this case bituminous coal. The Project is proposing to fire Illinois bituminous coal. The primary Illinois coal being proposed for the Project is Illinois Washed No. 6 coal with a typical sulfur content of 2.74 percent. Other Illinois coals may be fired in the boilers with expected sulfur contents ranging from 1.35 to 3.5 percent. In addition, to Illinois bituminous coals, the Project is evaluating the option to fire a limited amount of supplemental fuel, such as petcoke and waste coal, blended with the Illinois coal. Petcoke has a typical sulfur content of approximately 6 percent.

In the CFB boilers, SO_2 emissions are controlled through limestone injection into the boiler bed with the coal. The limestone calcines with heat to form calcium oxide (CaO). The CaO then reacts with SO_2 to form calcium sulfate ($CaSO_4$). The chemical reactions for this process are depicted below

$$CaCO_3\,(s) + \text{Energy} \rightarrow CaO\,(s) + CO_2\,(g)$$

$$2SO_2\,(g) + O_2\,(g) + 2CaO\,(s) \rightarrow 2CaSO_4\,(s)$$

These reactions occur with relatively good efficiency at the optimum boiler temperature of about 1,600°F. Additionally, the long residence time and good mixing in CFB boilers assists the reactions. The reaction products are captured as bottom ash from the boiler and as flyash in the fabric filter. Previous CFB boiler installations have demonstrated SO_2 control efficiencies of approximately 90-95 percent through injection of limestone into the boiler. The actual reduction efficiency is dependent upon the sulfur content of the fuel and the Ca/S ratio. All of the recently permitted CFB projects use limestone injection to control SO_2 emissions.

The Project is proposing to use limestone injection into the boiler to achieve an SO_2 emission rate of 0.18 lbs/MMBtu on a rolling 30 day average. This emission level will require an SO_2 removal efficiency of 96.2 percent (4.7 lbs/MMBtu uncontrolled) when firing the primary proposed coal (Illinois Washed No.6 bituminous coal). The boiler will achieve higher SO_2 removal efficiencies when firing higher sulfur fuels, such as petcoke. For example, when the boilers are firing Illinois Washed No.6 coal with a blend of 20 percent petcoke, the uncontrolled SO_2 emission rate will be 5.6 lbs/MMBtu. Therefore, an SO_2 control efficiency of 96.8 percent will be required within the boiler. It is estimated that based upon the range of sulfur contents in Illinois bituminous coals that may be fired in the CFB boilers, the boilers will achieve a maximum control efficiency of 97.5 percent when firing the worst case fuel (7.2 lbs/MMBtu). This control efficiency will be achieved in the boiler without additional controls.

The proposed SO_2 BACT emission rate of 0.18 lbs/MMBtu, with a maximum control efficiency of 97.5 percent, represents an emission rate and overall control efficiency consistent with recently permitted CFB boiler projects that have utilized add-on controls such as spray dryer adsorbers (SDAs). Table 5-3 provides a summary of SO_2 control efficiencies (where available) and emission limits for the projects identified in Table 5-1.

As demonstrated by recently permitted projects summarized in Table 5-3, the proposed SO_2 BACT emission rate of 0.18 lbs/MMBtu with a control efficiency upwards of 97.5 percent is equivalent to the most stringent limits achieved by any CFB project, including those that employ add-on controls. The higher SO_2 control efficiency of the CFB boilers for the Project will be achieved through increased injection of limestone into the boiler as compared to current CFB boiler installations. Increased experience with CFB boilers has shown that additional limestone can be injected into the boiler to achieve overall control efficiencies equal to projects with add-on SO_2 controls, without the additional capital and operating expense.

Table 5-3: Summary of PSD CFB Boiler SO_2 Permit Limits

Project	Permit Date	SO_2 Emission Limit (lb/MMBtu)	SO_2 Control Efficiency (%)	Add-On SO_2 Controls
Northampton Generating	01/95	0.129 (24-hr)	92	None
Toledo Edison – Bayshore	06/97	0.60	90	None
ADM – Illinois	12/98	0.70	92	None
ADM – Iowa	06/98	0.36 (30-day)	92	None
JEA Northside	07/99	0.15 (30-day) 0.20 (24-hr)	97.5 (24-hr)	SDA
Enviropower – IL	7/01	0.25 (30-day)	97.5 (design) 92.0 (minimum)	SDA
Energy Services of Manitowoc	6/01	0.20 (annual) 0.22 (24-hr)	97.5 (design)	SDA

During periods when firing relatively low sulfur coals, maintaining a very high SO_2 control efficiency becomes impractical. The Project proposes to maintain a minimum SO_2 control efficiency of 92 percent. As discussed above, a much higher control efficiency will be required when firing the primary coals for the Project.

The Project has not proposed to install a scrubber (SDA) since the SO_2 control provided by the CFB is equivalent to the control achieved by other CFB projects with add-on controls. However, an economic analysis was conducted to evaluate the cost to install an SDA on the Project to provide an overall SO_2 control efficiency of 99 percent. It should be noted that an overall control efficiency of 99 percent, and the equivalent emission limit of less than 0.05 lb/MMBtu for the primary coal, have not been achieved in practice by any known CFB boiler project. Therefore, the emission levels on which this economic analysis is based may not be attainable in practice.

An estimated capital cost and installation costs for an SDA was obtained from the CFB boiler vendor. Using these provided costs and other costing factors contained in EPA's *OAQPS Control Cost Manual*, annualized costs were estimated for the SDA. The tons of SO_2 removed were estimated based upon the proposed potential SO_2 emissions and a control efficiency of 70 percent for the SDA, thereby achieving an overall control efficiency of 99 percent. This control cost analysis is provided in Table 5-4.

The estimated installed capital cost for the SDA is over $30 million dollars with an annualized cost of nearly $7 million dollars per year. The cost to control, based upon the stated SO_2 reduction, is over $4,300 per ton. The Project believes that these costs are not cost effective based upon the high level of control achieved by the CFB alone and the uncertainty of achieving the emission levels upon which the cost analysis is based.

5.4.2.2 Miscellaneous Combustion Sources

The auxiliary boilers and limestone drying mills will exclusively fire natural gas. The most stringent method of control for SO_2 that has been demonstrated for combustion sources is limiting operation to natural gas only. The use of natural gas as the exclusive fuel represents BACT for SO_2 emissions for the auxiliary boiler and limestone drying mills.

The only SO_2 control technique available for emergency engines that operate 500 hours or less per year is the use of low sulfur fuel. The Project is proposing to fire low sulfur diesel oil with a maximum sulfur content of 0.05 percent in the fire pump and boiler cooling water pump diesel engines.

Table 5-4: SO_2 Scrubber Control Cost Analysis

Operating Hours	8,760	hr/yr	
SO2 Emissions From CFB	2,304	tpy	

	(Factor)		
Equipment Cost (EC)			
Polishing Scrubber Uninstalled Capital Costs		$16,500,000	*$50/kW*
Instrumentation (10% of Capital Costs)		Included	
Taxes and Freight (8% of Capital Costs)		$1,320,000	
	Total Equipment Cost (TEC)	**$17,820,000**	
Direct Installation Costs			
Foundation	(TEC*0.08)	$1,425,600	*OAPQS*
Erection and Handling	Vendor	$3,000,000	*Foster Wheeler*
Electrical	Vendor	$500,000	*Foster Wheeler*
Piping	Vendor	$500,000	*Foster Wheeler*
Insulation	(TEC*0.01)	NA	
Painting	(TEC*0.01)	NA	
	Total Direct Installation Cost	**$5,425,600**	
Indirect Installation Costs			
Engineering and Supervision	(TEC*0.1)	$1,782,000	*OAPQS*
Construction and Field Expenses	(TEC*0.05)	$891,000	*OAPQS*
Construction Fee	(TEC*0.1)	$1,782,000	*OAPQS*
Start Up/Performance Test	(TEC*0.03)	$534,800	*OAPQS*
Contingencies	(TEC*0.12)	$2,138,400	*Estimate*
	Total Indirect Installation Cost	**$7,128,000**	

[redacted]

Direct Annual Costs ($/yr)		
Operating/Supervisory Labor (1 person/shift, 3 shifts/day, 365 days/yr, $35/hr)		$306,600
Maintenance Costs (TEC x 0.05)		$891,000
Pebble Limestone Costs ($70/ton, 2:1 Ca to S)		$322,519
Limestone/Ash Waste Disposal ($20/ton)		$105,970
Performance Loss (306kWh @ $.060/kWh)		$160,834
	Total Direct Annual Cost	**$1,786,923**
Indirect Annual Costs ($/yr)		
Property Taxes, Insurance and Administration (0.04 x TCI)		$1,214,944
Capital Recovery (15 years @ 10%)		$3,993,217
	Total Indirect Annual Cost	**$5,208,161**

[redacted]

SO2 Controlled (tons/yr)	**1,613**	*70% SDA Control, 99% Overall Control*
Control Cost ($/ton SO2)	**$4,338**	

Sources: Capital equipment cost derived from vendor quotation
Installation costs provided by Foster Wheeler
Other costs from OAQPS Control Cost Manual (USEPA 1990a).

5.4.3 *Particulate Matter (PM_{10})*

5.4.3.1 *CFB Boilers*

PM_{10} emissions occur as a result of combustion of the coal in the CFB boiler and the carryover of flyash and limestone. The proposed method to control these emissions is fabric filtration to a level of 0.015 lb/MMBTU. It is proposed to install a pulse jet fabric filter downstream of the CFB boiler and upstream of the induced draft fan and stack. At the expected inlet concentrations, a removal efficiency of 99.9% will be required to achieve this emission limit.

All of the recently permitted CFB boiler projects identified in Table 5-1 use fabric filters (baghouses) or ESPs to limit PM/PM_{10} emissions ranging from 0.009 lb/MMBTU to 0.030 lb/MMBTU. The proposed BACT limit is consistent with the recently permitted Enviropower project in Illinois. The proposed BACT limit is also equal to or lower than the PM_{10} limits for recently permitted natural gas fired combustion turbine projects in Illinois including Duke Kankakee and Grand Prairie Energy, as well as numerous other natural gas combustion turbine projects throughout the country. Indeck Elwood, LLC believes that controlling PM/PM_{10} emissions to levels achieved by recent CFB boiler projects as well as recent natural gas fired combustion turbine projects represents BACT for the Project.

5.4.3.2 *Material Handling and Storage*

Other potential sources of PM/PM_{10} emissions are material handling processes for the coal, petcoke, ash, and limestone. Enclosing all unloading, storage, processing, and handling operations will control PM/PM_{10} emissions from these operations. The only true fugitive dust sources for the Project are the bed ash and fly ash loadout processes. The bed ash and fly ash loadout operations will utilize wet mixers to raise the moisture content of the ash to approximately 25 percent before loading into railcars. The railcars will be covered to prevent dust emissions during transit to the ash disposal location.

The Project will fully enclose the fuel and limestone storage piles to minimize fugitive emissions. The material handling operations within both the live and dead storage buildings will employ wetting at transfer points to reduce the generation of fugitive dust. Since the piles will be completely enclosed within buildings, there will be no wind generated fugitive dust emissions. Any fugitive dust generated during reclaim operations or other material handling activities within the live storage building will be vented through two fabric filter points. Fugitive emissions generated in the dead storage building will be emitted through general ventilation roof vents.

Fabric filters will be employed on the exhaust systems throughout the enclosed material handing operations. Fabric filter systems will be used to control the following material handling operations: limestone reclaim; the coal crusher house; the limestone preparation building including the drying mills; the live storage building tripper floor; and the coal, limestone, bed ash, and fly ash storage silos. These fabric filters will reduce particulate loading in the exhausts to less than 0.005 grains per standard cubic foot (gr/scf). Many of the emission points will be controlled down to 0.001 gr/scf to minimize ambient impacts. Enclosing all of the material handling operations and exhausting these operations through fabric filters represents the highest level of PM/PM_{10} control available for these processes.

The PM/PM_{10} emission limits proposed for the Project are consistent with limits proposed for recently permitted coal fired boiler projects. Emission limits for material handling and storage operations for other recently permitted coal projects are provided in Table 5-5.

Table 5-5: Material handling PM/PM_{10} Limits For Recently Permitted Projects

Facility	Emission Source	Permit Limit (gr/dscf)
York County Energy	Coal, limestone, & ash handling	0.02
JEA Northside	Limestone Handling	0.01
Enviropower of Illinois	Coal, limestone, & ash handling	0.01
Kentucky Mountain Power	Limestone Handling	0.005
Energy Services of Manitowoc	Coal Handling Limestone Handling Limestone Silo Ash Handling	0.004 0.004 0.009 0.02

The proposed limits for the Project are consistent with recently permitted projects. BACT is proposed to be enclosing all material handling and storage operations, employ wet dust suppression systems at all material transfer point locations, and employ fabric filters on all exhaust points to reduce the exhaust concentration to no greater than 0.005 gr/dscf.

5.4.3.3 Plant Roadways

PM and PM_{10} emissions may be generated from plant roadways as a result of normal truck traffic. The facility will employ dust minimization procedures to limit the generation of fugitive PM/PM_{10} emissions. All plant roadways will be paved. Furthermore, the plant will utilize road spraying and road sweepers to further control dust emissions from the plant roadways.

5.4.3.4 *Cooling Tower*

Cooling towers are designed to efficiently evaporate water. As water evaporates, it absorbs heat, causing the remaining water to become colder. The cold water is then circulated in non-contact heat exchangers to remove heat from the steam condenser. Water not lost to evaporation in the cooling tower is used for non-contact cooling of the steam turbine condenser. This water will contain dissolved solids. As the water is evaporated in the cooling tower, these total dissolved solids (TDS) tend to concentrate in the water that remains circulating within the cooling tower.

To improve evaporation rate, cooling towers are designed to induce a flow of fresh air across a large wetted surface area (called "fill"). This induced airflow, however, entrains some of the fine water droplets that carry out of the tower, referred to as drift. These fine droplets subsequently evaporate in the ambient air, but when they do they liberate the total dissolved solids that were formerly in solution as PM/PM_{10} emissions.

The technologies that are available to control PM_{10} emissions from evaporative cooling towers are limited to devices that minimize drift. These devices are known as drift eliminators. Drift eliminators typically consist of layers of plastic chevrons located within the tower to knock out and coalesce fine water droplets before they can be emitted to the atmosphere. Drift eliminators represent the top level of control of PM_{10} emissions from evaporative cooling towers.

An evaluation of drift performance guarantees was conducted based upon state-of-the-art commercially available drift eliminators. Based on this evaluation, a guaranteed level of 0.0005 percent of circulating water flow was obtained for this project. This level of control results in a potential annual emission of PM/PM_{10} from the two cooling towers combined of 8.4 tpy.

5.4.3.5 *Miscellaneous Combustion Sources*

Natural gas is a clean burning fuel, it contains essentially no inert solids (ash). The auxiliary boiler and limestone grinding mills will fire natural gas exclusively. For the emergency diesel engines, firing the lowest sulfur and ash containing diesel fuel will minimize PM/PM_{10} emissions.

5.4.4 Carbon Monoxide (CO)

5.4.4.1 CFB Boilers

CO emissions are formed due to incomplete combustion of the fuel in any combustion process. CO emissions from CFB boilers are somewhat higher than pulverized coal boilers. These higher CO emissions are a result of the lower combustion temperatures found in CFB boilers, thereby causing slightly less complete combustion. Still, good combustion is achieved by the CFB due to good mixing, uniform bed temperature, long residence time, and good combustion control. Additionally, the lower combustion temperatures minimize NO_x emissions and promote higher SO_2 collection in the CFB boiler.

The CO emission rate from the boilers will be dependent upon operating load. At full operating load, the CO emission rate will be 0.11 lb/MMBtu, which is consistent with the lowest emission levels for recent CFB projects identified in Table 5-1. However, as the operating loads decreases, the CO emission rate will increase. At the minimum expected operating load of 50 percent, the CO emission rate will be 0.19 lb/MMBtu. However, the CO emission rate in pounds per hour at 50 percent load will be less than at full load. The Project proposes CO BACT to be maximum emission rates of 0.19 lb/MMBtu and 321.4 lb/hr. The maximum proposed emission rate of 321.4 lbs/hr is equivalent to an emission rate of 0.11 lb/MMBtu at full load.

Some combustion processes have applied an oxidation catalyst as add-on control to further reduce CO emissions. An oxidation catalyst is a passive reactor that consists of a metal grid coated with platinum catalyst that is placed in the gas exhaust at a temperature range of 700°F to 900°F. This would place the catalyst in the convective backpass of the boiler, downstream of the SNCR system and upstream of the combustion air preheater and fabric filter. This type of control system is technically infeasible for the following reasons:

- Trace metals in the coal flyash could poison the catalyst;
- The catalyst would be prone to pluggage by flyash and calcium sulfate;
- The catalyst would oxidize SO_2 to SO_3 leading to corrosive and sticky ammonium sulfate salts by reaction with excess ammonia from the SNCR system, which could cause corrosion and plugging of downstream equipment.

There are no known applications of a CO oxidation catalyst on a coal fired boiler project. Therefore, good combustion is considered BACT for the Project.

5.4.4.2 Miscellaneous Combustion Sources

The auxiliary boiler will employ good combustion controls to minimize CO emissions. Catalytic oxidation of CO is the most stringent method of control on some combustion systems. However, there are no known installations of oxidation catalysts on low utilization package boilers. Because of the restricted operating hours (2500 hr/yr) for this unit and the corresponding lack of operating history, a CO oxidation catalyst is not considered to represent BACT. Therefore, BACT is concluded to be good combustion controls for the auxiliary boiler. The gas fired auxiliary boiler CO emission rate in the exhaust gas will be limited to 0.084 lb/MMBtu through the use of good combustion control.

The limestone drying mills will employ good combustion controls to minimize CO emissions. Due to the size of these emission sources and the relatively minor amount of CO emissions, back end controls are not economically feasible. Therefore, BACT is concluded to be good combustion controls for these sources. The limestone drying mills will meet a CO emission rate of 0.20 lb/MMBtu through the use of good combustion control.

Add-on controls for CO emissions have never been applied to emergency engines that operate less than 500 hours/year. Combustion controls and limited operating hours (500 hours/yr for each engine) is concluded to represent BACT for the firewater pump and boiler cooling water pump engines.

5.4.5 Control of Non-Criteria PSD Pollutants

The Project will emit four PSD regulated non-criteria pollutants above their respective significance threshold, sulfuric acid mist, beryllium, mercury and fluorides. Therefore, the Project is subject to PSD review for emissions of these pollutants, including a BACT analysis.

Sulfurie acid mist emissions result from the oxidation of a small percentage of SO_2 to SO_3 and the reaction of SO_3 with water to form sulfuric acid. The limestone injection into the CFB boiler used to control SO_2 emissions also controls SO_3 emissions thereby limiting emissions of sulfuric acid mist. Additional control of sulfuric acid mist is achieved through buildup of calcium oxide on the fabric filter and some incidental control may be achieved by reaction with excess ammonia from the SNCR system.

Fluorides are emitted as hydrogen fluoride (HF) from the boilers. HF is an acid gas much like sulfuric acid and the mechanisms employed to control sulfuric acid mist emissions will also control HF emissions. BACT for sulfuric acid and fluoride (HF) emissions is proposed to be injection of limestone into the CFB boiler.

Beryllium will be emitted as PM/PM_{10} and the Project is installing a fabric filter as BACT for PM/PM_{10}. Fabric filters represent the highest level of control available to control PM/PM_{10} emissions and therefore fabric filters are proposed as BACT for beryllium emissions.

Mercury emissions from the boilers are also subject to Maximum Available Control Technology (MACT) controls. The proposed MACT controls as discussed in Section 5.6 are proposed as BACT for mercury emissions from the Project.

5.5 LAER - Volatile Organic Material (VOM)

5.5.1 CFB Boilers

Similar to CO emissions, VOM emissions are formed due to incomplete combustion of the fuel in any combustion process. Likewise, conditions designed to reduce NO_x emissions also tend to slightly increase VOM emissions. However, the proposed boiler will incorporate state of the art combustion controls to minimize VOM emissions.

The VOM emission rate from the boilers will also be dependent upon operating load. At full operating load, the VOM emission rate will be 0.004 lb/MMBtu, which is lower than or equal to all of the recent CFB projects identified in Table 5-1. However, as the operating load decreases, the VOM emission rate will increase. At the minimum expected operating load of 50 percent, the VOM emission rate will be 0.007 lb/MMBtu. However, the VOM emission rate in pounds per hour at 50 percent load will be equal to the full load emission rate. The Project proposes VOM BACT to be maximum emission rates of 0.007 lb/MMBtu and 11.7 lb/hr. The maximum proposed emission rate of 11.7 lbs/hr is equivalent to an emission rate of 0.004 lb/MMBtu at full load.

There are no commercially available add-on controls to reduce VOM emissions from coal-fired boilers. Good combustion practices are the sole emission reducing technique available to control VOM emissions. The proposed VOM emission limit is lower than or equal to the VOM limits for other CFB boiler projects, and therefore represents VOM LAER for the Project.

5.5.2 Miscellaneous Combustion Sources

The auxiliary boiler, limestone drying mills, and emergency diesel engines will employ good combustion controls to minimize VOM emissions. The auxiliary boiler will operate less than 2500 hours per year and the emergency engines less than 500 hours per year. The application of good combustion controls and restricted operating hours represents LAER for VOM emissions from these sources.